**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – December 14, 2017**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of August 31, 2017, OPG projected a $130 million cash position at the end of 2017. OPG continues to assume no payment of dividends in its financial projections.
    - OPG had a $186 million cash position at the end of 2016.

**Commented [EJ1]:** Please note, we only have information up to Aug. 31, 2017. We have reached out to Ministry of Energy for the latest updates from OPG, but there is no guarantee we may receive the updates in time for the Board Meeting package preparation due date.

- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- OPG has borrowed a total of $800 million under the credit facility year-to-date. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. OPG has stated in their third quarter financial results that the OEB is expected to make a decision prior to the end of 2017. Adverse OEB decisions, with respect to OPG's rate application including,

the effective date for new rates, the revenue requirement request, and proposed rate smoothing, would affect OPG's longer term liquidity outlook.

- **OPG Current Financial Outlook, based upon financing updates up to August 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 2017 Actual | Q2-Q4 2017 Forecast | 2017 Forecasted |
|---|---|---|---|
| **Opening Cash** | **186** | **220** | **186** |
| Cash from Operations | 118 | 684 | 802 |
| Approved Capital Expenditures | (408) | (1,572) | (1,980) |
| PS Term Deposit Maturity | 45 | 25 | 70 |
| Pre-tax Proceeds – Sale of Head Office | - | 484 | 484 |
| Pre-tax Proceeds – Sale of Hearn Site | - | 16 | 16 |
| Maturing Debt | (50) | (1,053) | (1,103) |
| New Debt to OEFC* | 200 | 1,550 | 1,750 |
| Commercial Paper | 133 | 70 | 203 |
| Proceeds of Distribution to Trillium Trust** | - | (283) | (283) |
| Distributions to Non-Controlling Interest | (4) | (12) | (16) |
| Dividends | - | - | - |
| **Net Cash flow** | **34** | **(90)** | **(57)** |
| **Ending Cash** | **220** | **130** | **130** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan.

** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.
Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**December 5, 2017**



# OPG's Financial Outlook
# Shareholder Briefing

September 2017 Update

ONTARIO POWER GENERATION



# Net Income – Shareholder's Year Ending March 31, 2018

**Shareholder's Fiscal Calendar – Year Ending March 31, 2018**

| *$ millions* | 2017/2018 Forecast | Assumed Provincial Budget | Variance from Assumed Provincial Budget |
|---|---|---|---|
| **Total Gross Margin** | 4,527 | 4,578 | (51) |
| **Total Expenses (excl. Cost of Goods Sold)** | 3,925 | 4,006 | (81) |
| **Gain on the sale of OPG's head office property** | 377 | 296 | 82 |
| **Income Attributable to Shareholder Before Income Tax** | **980** | **868** | **112** |
| **Income Tax Expense** | 162 | 166 | (4) |
| **Net Income Attributable to Shareholder After Income Tax** | **818** | **702** | **116** |

- The net income projection is higher than the assumed Provincial budget by $116 M. The main drivers of the favourable variance are as follows:
  - Higher nuclear generation due to strong performance at Pickering (i.e., early completion of planned outages and better forced loss rate performance)
  - Higher generation and lower OM&A expenses related to the deferral of the Pickering Unit 6 planned outage to start in January 2018
  - Lower OM&A expenses due to labour and other savings, as well as lower project spending
  - Higher gain from the sale of OPG's head office property
  - The above factors are partially offset by the change in corporate provisions
- The forecast remains subject to OEB's decision on OPG's rate application. OPG continues to assume the recovery of nuclear decommissioning and nuclear waste management liabilities using the current OEB-approved, accounting-based methodology, as opposed to a prospective cash basis as advocated by certain intervenors. Use of a cash-based methodology would materially reduce OPG's revenue and net income going forward.
- In May 2017, the OEB issued a report that established accrual accounting as the default method for recovery of pension and OPEB amounts. In a final report issued in September 2017, the OEB confirmed that asymmetric carrying charges in favour of ratepayers on the difference between accrual cost recoveries and cash payments will apply to amounts recorded by OPG in a deferral account since November 2014, once the deferred amounts begin to be collected in the future. In order to avoid writing off a portion of the deferral account balance against net income under US GAAP, OPG must begin to collect it by November 2019. The balance in the deferral account is projected at approximately $600 million by December 31, 2017.
- The assumed Provincial budget and current forecast do not reflect the anticipated impacts of the Fair Hydro Plan on OPG's financial results, and do not include a gain on the expected sale of the Lakeview site, which OPG expects to close in 2018.



# Net Income Changes – Shareholder's Year Ending March 31, 2018

## Comparison to Previous Projection

| *$ millions* | Fav / (Unfav) | |
|---|---|---|
| | Pre-Tax | After-Tax |
| **Previous Projection** | **962** | **803** |
| **Key Drivers:** | | |
| *Gross Margin* | | |
| Primarily higher forecast nuclear generation revenue due to updated regulatory assumptions | 20 | |
| *OM&A (excl. Cost of Goods Sold)* | - | |
| *Other* | (1) | |
| *Income Taxes* | | **(3)** |
| **Total Change from Previous Projection** | **18** | **15** |
| **Year-end Projection** | **980** | **818** |

## Comparison to Province's Assumed Reporting Base

| *$ millions* | Fav / (Unfav) | |
|---|---|---|
| | Pre-Tax | After-Tax |
| **Assumed Provincial Budget** | **868** | **702** |
| **Key Drivers:** | | |
| *Gross Margin* | | |
| Primarily due to change in corporate provisions, partially offset by higher nuclear generation as a result of earlier than planned completion of Pickering Unit 4 and Unit 5 planned outages, the deferral of Pickering Unit 6 planned outage to January 2018 and higher regulated hydroelectric margin | (51) | |
| *OM&A (excl. Cost of Goods Sold)* | | |
| Primarily due to the deferral of Pickering Unit 6 planned outage to January 2018, labour savings and lower project spending | 38 | |
| *Seg. Fund Earnings* | 6 | |
| *Higher gain from the sale of OPG's head office property* | 82 | |
| *Other* | | |
| Primarily due to the deferral of the sale of the land at the Hearn site from Q1 2017 to later in 2017, and lower interest and depreciation expenses | 36 | |
| *Income Taxes* | | **4** |
| **Total Change from Assumed Budget** | **112** | **116** |
| **Year-end Projection** | **980** | **818** |



# 2017 Liquidity Outlook

| *$ millions* | Actual Q1 2017 | Forecast Q2-Q4 2017 | Forecast 2017 |
|---|---|---|---|
| **Opening Cash Balance** | **186** | **220** | **186** |
| Net Operating Cash Inflow | 274 | 1,173 | 1,447 |
| Interest | (72) | (212) | (284) |
| Pension Fund Contribution | (63) | (185) | (248) |
| OPEB Payments | (21) | (92) | (113) |
| **Net Cash from Operations** | **118** | **684** | **802** |
| **Investing Activities** | | | |
| Sustaining Capital Expenditures | (86) | (522) | (607) |
| Darlington Refurbishment | (306) | (981) | (1,287) |
| Peter Sutherland Sr. GS (PS) | (23) | (28) | (51) |
| Ranney Falls GS | (2) | (25) | (27) |
| Other Generation Development | 8 | (17) | (9) |
| **Total Capital Expenditures** | **(408)** | **(1,572)** | **(1,980)** |
| PS Term Deposit Maturity | 45 | 25 | 70 |
| Pre-tax Proceeds Net of Closing Costs - Sale of OPG Head Office* | - | 484 | 484 |
| Pre-tax Proceeds - Sale of Hearn Site | | 16 | 16 |
| **Net Cash for Investment** | **(363)** | **(1,047)** | **(1,410)** |
| **Financing Activities** | | | |
| LT Debt - Corporate | 200 | 1,550 | 1,750 |
| LT Debt Retirement | (50) | (1,053) | (1,103) |
| Commercial Paper / ST Debt | 133 | 70 | 203 |
| Distributions to Non-Controlling Interests | (4) | (12) | (16) |
| Distribution of Head Office Proceeds to Trillium Trust | - | (283) | (283) |
| **Net Cash from Financing** | **279** | **272** | **551** |
| **Total Cash Flow** | **34** | **(90)** | **(57)** |
| **Ending Cash Balance** | **220** | **130** | **130** |

*Represents gross proceeds of $508 M, less estimated closing costs of $24 M

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing subsequent unit refurbishments after Unit 2 is successfully returned to service.

We continue to support the planned operation of Pickering units up to 2024 as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to seek concurrence to proceed with ongoing Pickering operation after the necessary regulatory approvals are complete.

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of costs to consumers for future decommissioning and long-term management of waste from Ontario's nuclear plants. In addition, the segregated nuclear funds set aside under ONFA have reached fully funded status. With many decades of nuclear generation in the Province's future, the decision to fund these costs now provides security for future generations of Ontarians.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial

and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy

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**Commented [RK1]:** Recommended not to use this wording, particularly also using the fully-funded wording that follows.

Under ONFA, for prudence, the Province required OPG to accelerate contributions to the funds, in advance of collecting the amounts from ratepayers. Even if the funds are currently estimated to be fully-funded, OPG (and the Province as Shareholder) still needs to recover its nuclear liabilities costs in rates.

**Commented [RK2]:** If wording is retained, should be reworded.

"As a result of the lower estimated liabilities and recent financial market performance, the segregated nuclear funds set aside under ONFA are currently estimated to be fully funded."

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

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Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Ali Ghiassi, Chief of Staff, Ministry of Finance
Scott Thompson, Deputy Minister, Ministry of Finance
Serge Imbrogno, Deputy Minister, Ministry of Energy

**Commented [RK3]:** Only add in if Energy CoS is included.

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**Commented [RK2]:** If wording is retained, should be reworded.

"As a result of the lower estimated liabilities and recent financial market performance, the segregated nuclear funds set aside under ONFA are currently estimated to be fully funded."

**Commented [FC3R2]:** Should be noted that the funds are fully funded today but changes in market conditions could put the funds in a temporary deficit position in a very short period.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Ali Ghiassi, Chief of Staff, Ministry of Finance
Scott Thompson, Deputy Minister, Ministry of Finance
Serge Imbrogno, Deputy Minister, Ministry of Energy

**Commented [RK4]:** Only add in if Energy CoS is included.

Ontario

MINISTRY OF
ENERGY

# OPG Business Plan

May 2017

# Context

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29 for concurrence
  - Please note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- The Minister's concurrence is subject to an appearance of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance
- The following presentation provides an overview of OPG's business plan, including:
  1. Business Plan Overview
  2. Other Considerations

# Context *(cont'd)*

- Proceeding with Provincial concurrence now will ensure OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP, these changes are not reflected in OPG's plan

  - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed by capital infusions from the Province, and by third-party lending

  - These changes are expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income

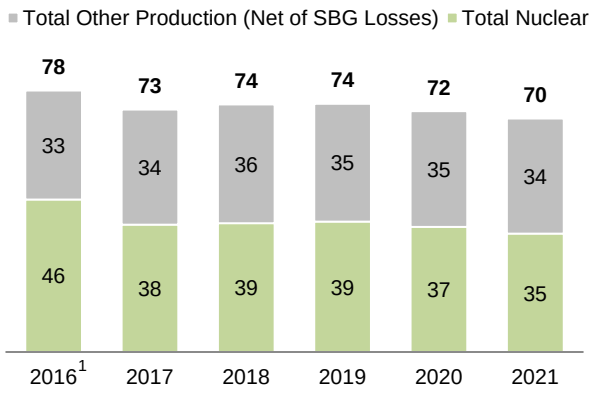
  - In addition, the Province's net debt position should remain unchanged

# 1. Business Plan Overview

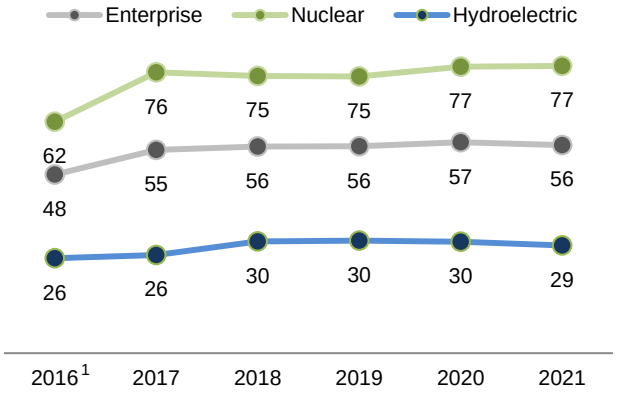
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- OPG's production is expected to fall to 69.8 TWh by 2021 from 78.2 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Also includes a partial overlap starting in 2021 between second and third unit refurbishments
- While Operations, Maintenance and Administration (OM&A) remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

### Production (TWh)




### Total Generating Cost ($/MWh)




1. Actuals

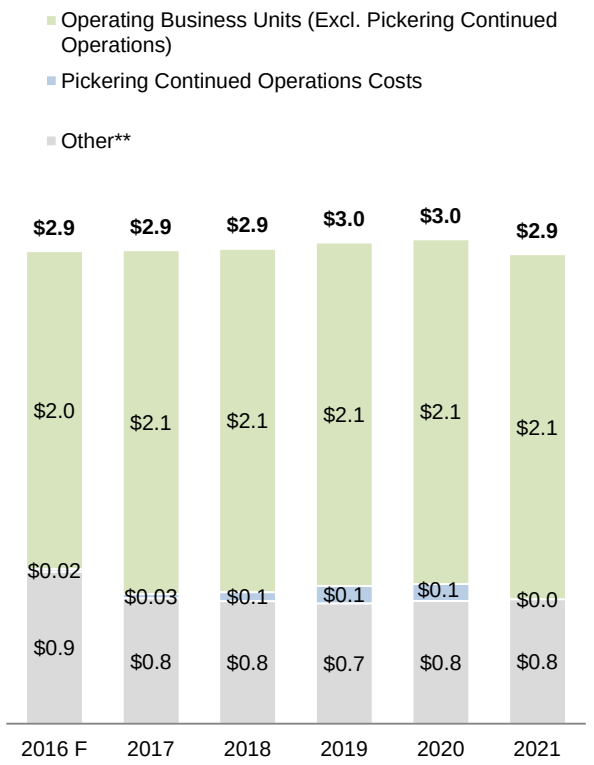
*TGC = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

# 1. Business Plan Overview

## *b) Operations, Maintenance and Administration (OM&A) Expenses*

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
  - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
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  - Partially offset by declining pension and OPEB costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

### OM&A from Ongoing Operations* ($B)



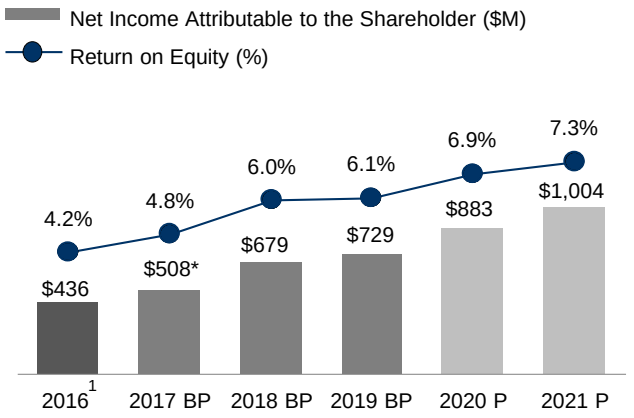

*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
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# 1. Business Plan Overview

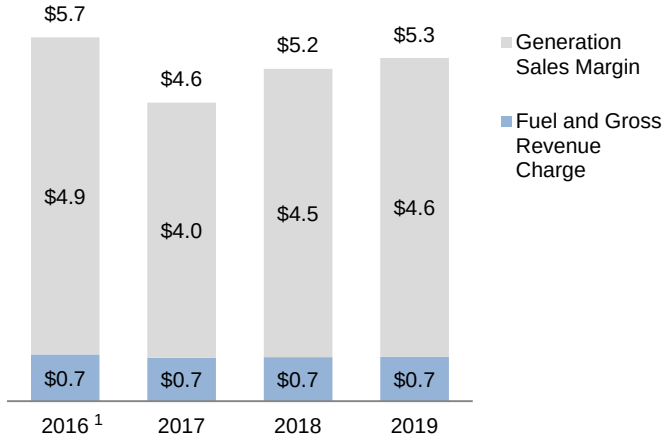
## *c) Financials*

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
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  - Net income in 2018 and 2019 is planned to increase, primarily due to higher production, and earnings from oncoming stations including Nanticoke solar in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return

### Net Income ($M) and ROE (%)




### Revenue Margin ($B)




*Includes extraordinary gain associated with the sale of OPG head office

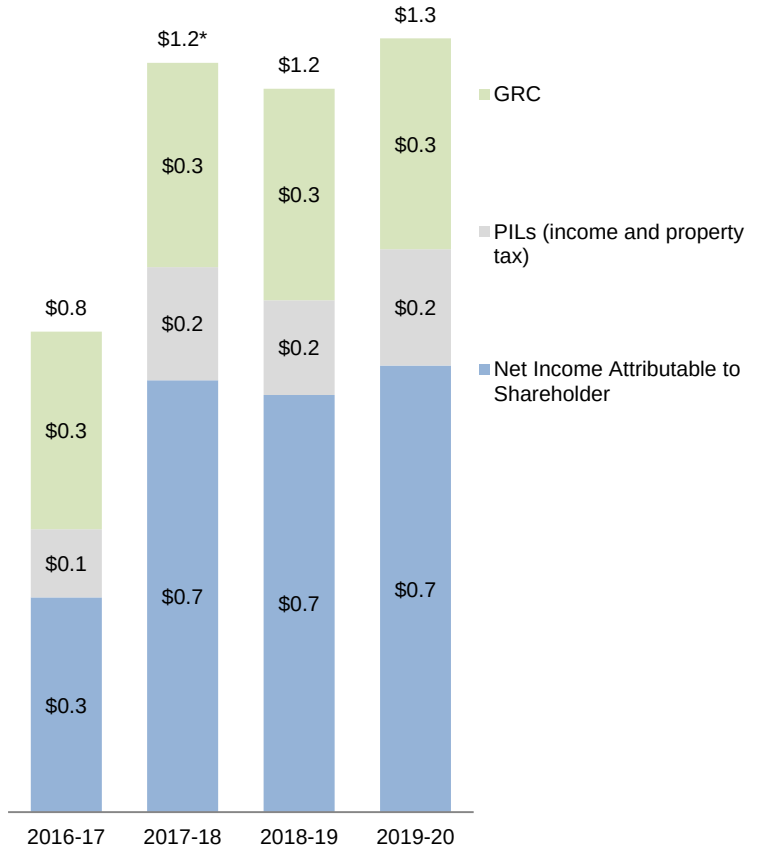
1. Actuals

# 1. Business Plan Overview

## *d) Shareholder Return*

- Total return to the shareholder averages ~$1B over the period
- Total return to the shareholder improves over the period largely due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs) income tax PILs are consolidated by the Ontario Electricity Financial Corporation (OEFC)
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**Total Shareholder Return ($B)**



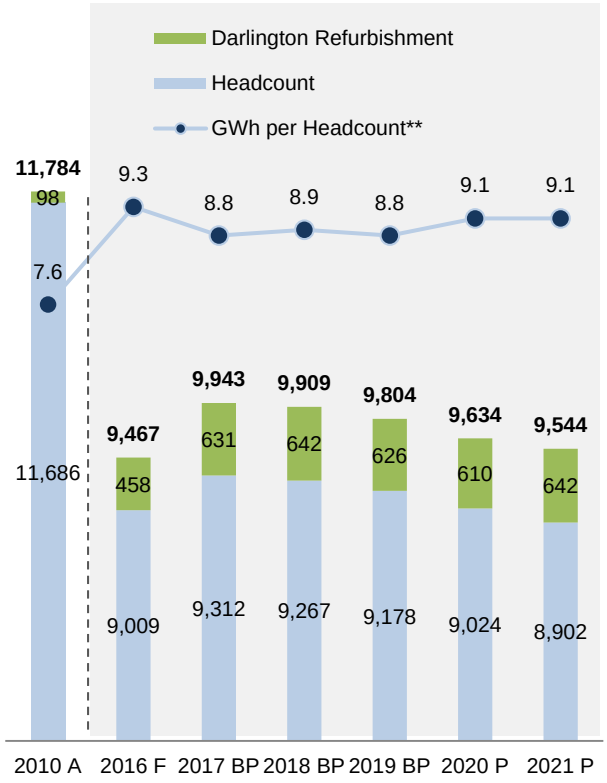

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# 1. Business Plan Overview

## *e) Business Transformation Initiative & Labour Costs*

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  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
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- In addition, to date OPG has hired ~60 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations

**Ongoing Operations Regular Headcount and Productivity**



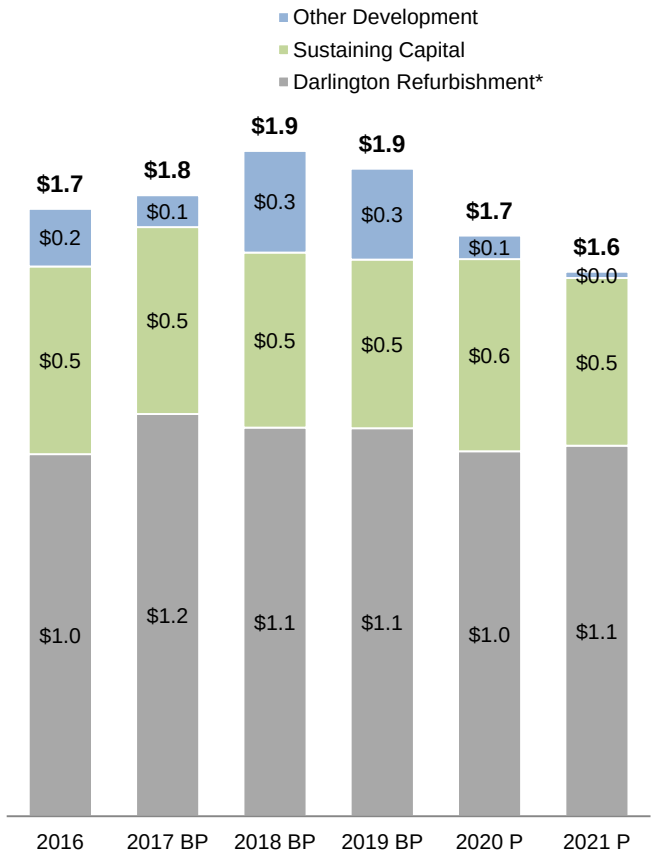

**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

# 1. Business Plan Overview

## *f) Operating Highlights - Projects and Capital Expenditures*

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
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    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew II
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Developments:** Investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility

**Capital Expenditure Estimates ($B)**




*Includes expenditures budgeted by Support Services

# 2. Other Considerations

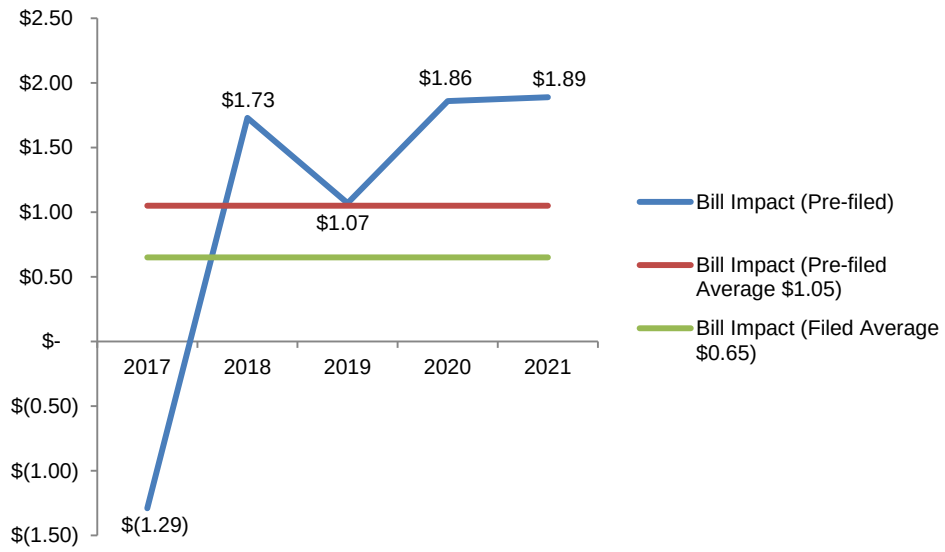
## *Rate Application*

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q3 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

**Rate-Smoothing Proposal:**

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

**Comparison of Annual Bill Impact ($/Month per year)**




*Forecasted in May 2016

# 2. Other Considerations

*Sales*

| | OPG Head Office | R.L. Hearn Site | Lakeview Site |
|---|---|---|---|
| **Current Status** | Completed | Agreement Reached | OPG and Infrastructure Ontario are preparing for marketing |
| **Site Description** | 700 University Ave. and parking garage at 40 Murray St. in Toronto | ~33 acres at the R.L. Hearn site in Toronto | ~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands) |
| **Buyer** | KingSett Canadian Real Estate Income Fund LP | Studios of America Limited Partner | TBD |
| **Value** | Estimated up-front 2017-18 fiscal impact of ~$375M | TBD | TBD |
| **Other Considerations** | N/A | N/A | Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition |
| **Timing** | The sale closed in April 2017 | Anticipated to close in Q3 2017 | Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017 |

# 2. Other Considerations

## *Special Status for OPG to Approve International Travel*

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister requesting authority for OPG to approve international travel for its employees
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- OPG has indicated that international travel is integral to the safe and prudent operation of its business and that special status will enable efficient decision-making while lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected see increases
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

# Appendix

# 2016 Year-End Financials

| OPG Balance Sheet as at Dec 31<br>$B | 2016 |
|---|---|
| **Assets** | |
| Cash and cash equivalents | 0.2 |
| Available-for-sale securities | 0.2 |
| Receivables from related parties | 0.4 |
| Nuclear fixed asset removal and nuclear waste management funds | 0.02 |
| Other current assets | 0.9 |
| **Total current assets** | **$1.7** |
| **Net property, plant and equipment** | **$20.0** |
| **Net intangible assets** | **$0.1** |
| Nuclear fixed asset removal and nuclear waste management funds | 16.0 |
| Regulatory assets | 5.9 |
| Other long-term assets | 0.7 |
| **Other assets** | **$22.5** |
| **Total assets** | **$44.4** |
| **Liabilities** | |
| Accounts payable and accrued charges | 1.2 |
| Short-term debt and long-term debt due within one year | 1.1 |
| Income taxes payable and other current liabilities | 0.1 |
| **Total current liabilities** | **$2.4** |
| Long-term debt | 4.4 |
| Fixed asset removal and nuclear waste management liabilities | 19.5 |
| Pension liabilities | 3.0 |
| Other post-employment benefit liabilities | 2.9 |
| Other liabilities | 1.7 |
| | **$31.5** |
| **Total liabilities** | **$33.9** |
| **Equity** | |
| Equity attributable to the Shareholder | 10.4 |
| Equity attributable to non-controlling interest | 0.1 |
| **Total equity** | **$10.5** |
| **Total liabilities and equity** | **$44.4** |

| OPG Income Statement Year Ended Dec 31<br>$B | 2016 |
|---|---|
| Revenue | $5.7 |
| Fuel expense | 0.7 |
| **Gross margin** | **$4.9** |
| Operations, maintenance and administration | 2.7 |
| Depreciation and amortization | 1.3 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 0.9 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | -0.7 |
| Other expenses | 0.02 |
| **Total expenses** | **$4.2** |
| **Income before other (gains) losses, interest and income taxes** | **$0.7** |
| Other (gains) losses | -0.02 |
| **Income before interest and income taxes** | **$0.7** |
| Net interest expense | 0.1 |
| **Income before income taxes** | **$0.6** |
| Income tax expense | 0.2 |
| **Net income** | **$0.5** |
| **Net income attributable to the Shareholder** | **$0.4** |
| **Net income attributable to non-controlling interest** | **$0.02** |

Ontario

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# OPG Business Plan

May 2017

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- The following presentation provides an overview of OPG's business plan, including:
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- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

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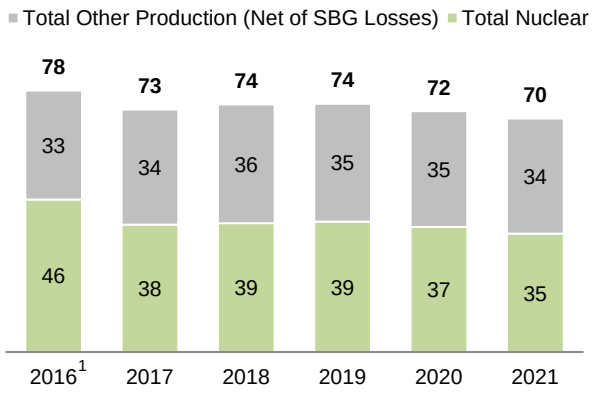
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# 1. Business Plan Overview

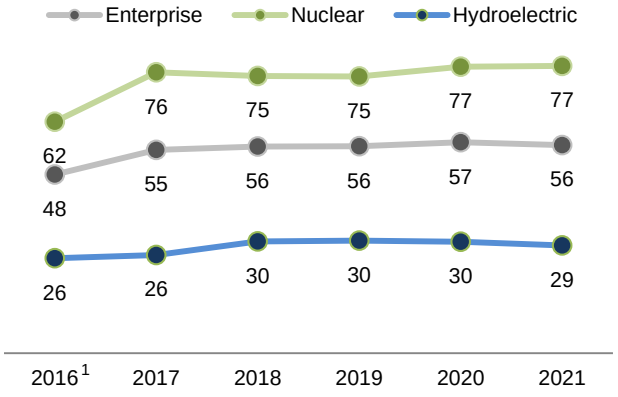
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### Production (TWh)




### Total Generating Cost ($/MWh)




1. Actuals

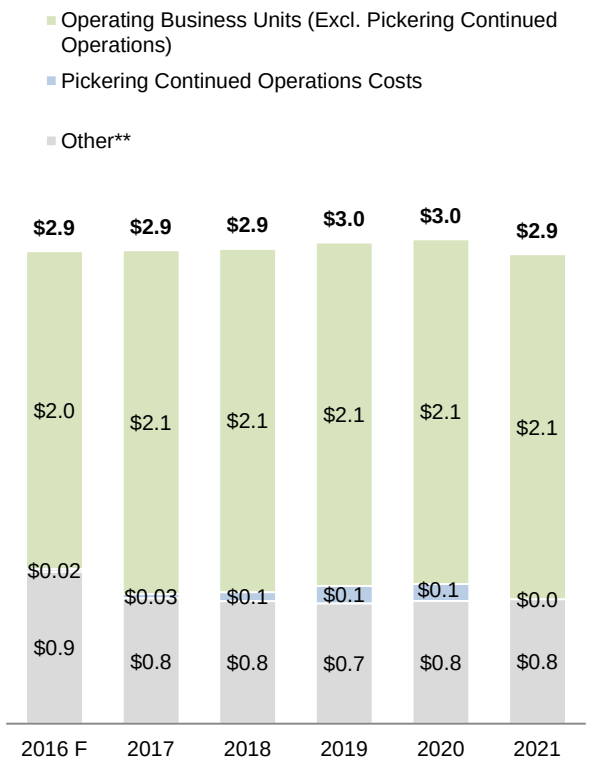
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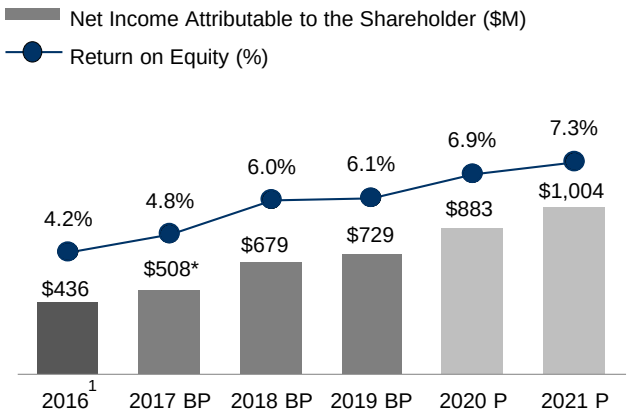

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# 1. Business Plan Overview

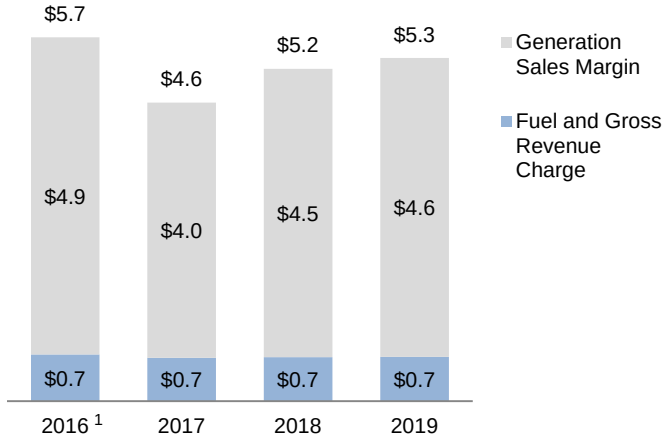
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### Revenue Margin ($B)




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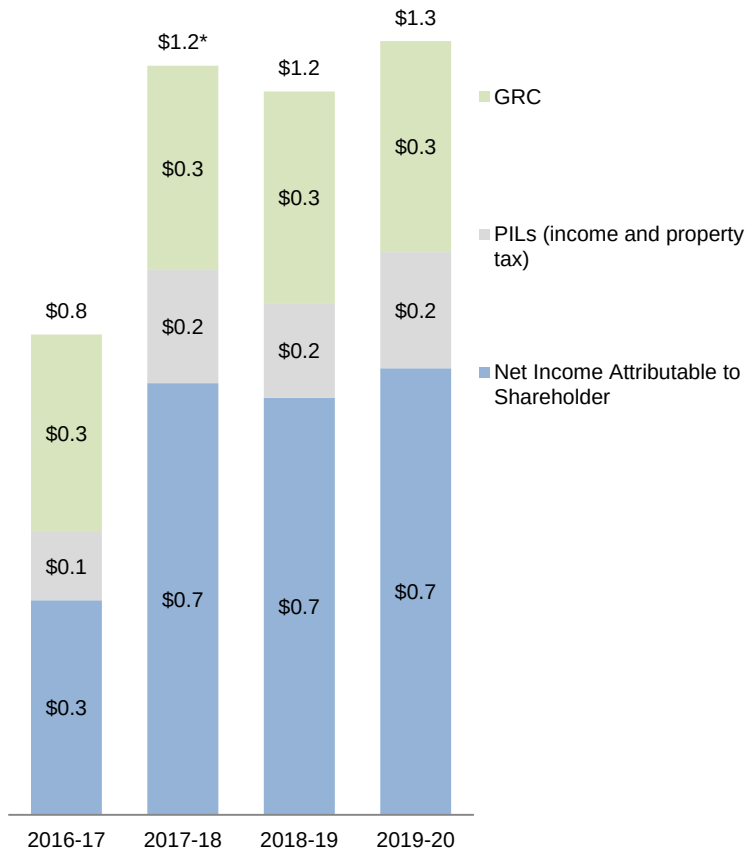
1. Actuals

# 1. Business Plan Overview

## *d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes*

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG.
- ~~Total r~~Return to the shareholder improves ~~over the period largely~~ due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
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**Total Fiscal Revenues ~~Shareholder Return~~ ($B)**



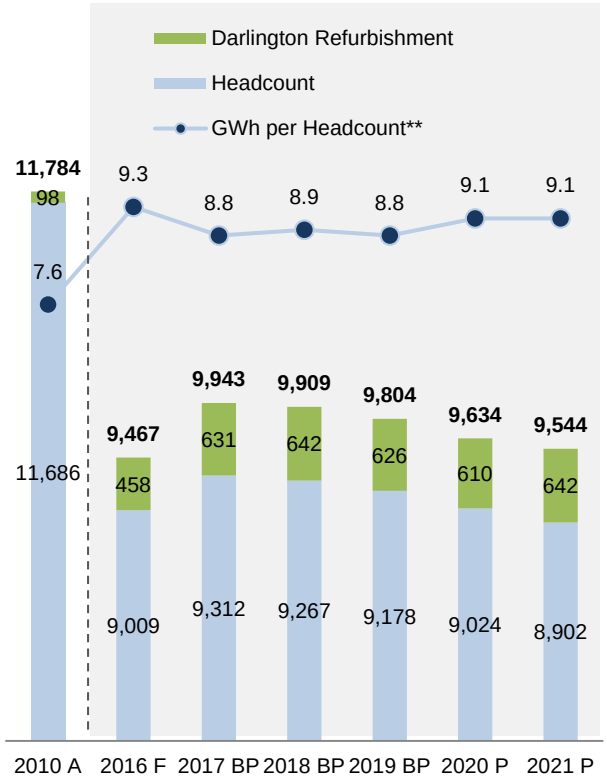

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# 1. Business Plan Overview

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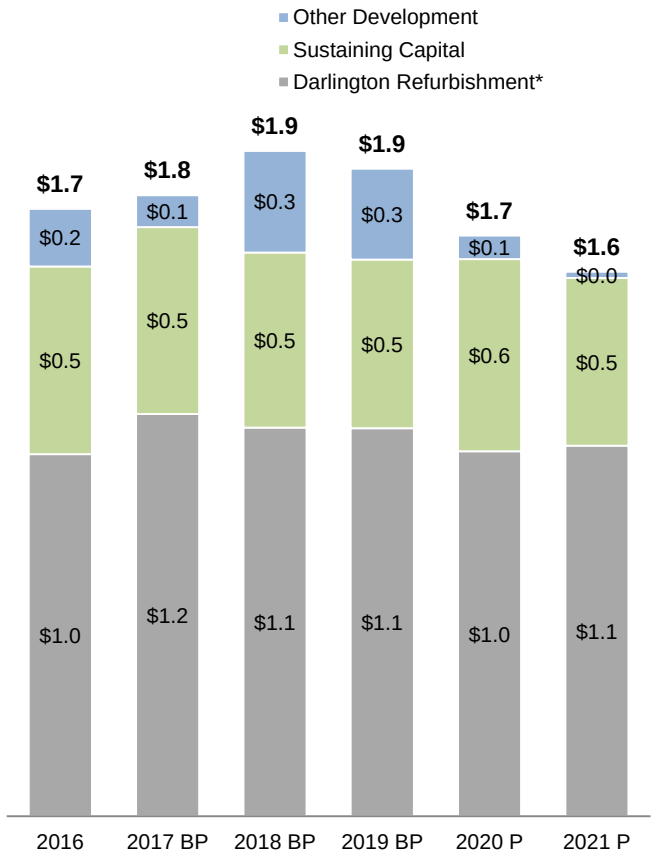

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**Capital Expenditure Estimates ($B)**




*Includes expenditures budgeted by Support Services

# 2. Other Considerations

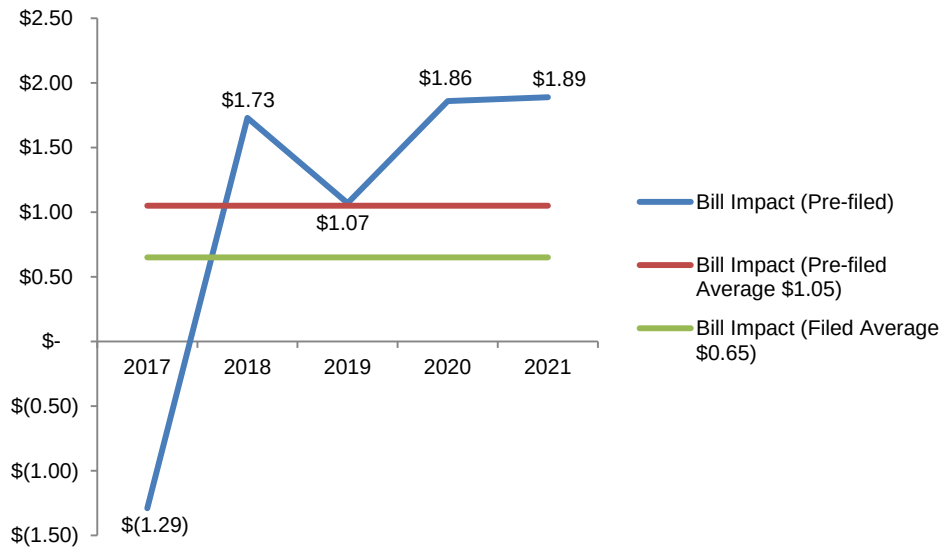
## *Rate Application*

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q3 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

**Rate-Smoothing Proposal:**

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's total bill impact, rather than on the basis of nuclear rates only
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

**Comparison of Annual Bill Impact ($/Month per year)**




*Forecasted in May 2016

# 2. Other Considerations

*Sales*

| | OPG Head Office | R.L. Hearn Site | Lakeview Site |
|---|---|---|---|
| **Current Status** | Completed | Agreement Reached | OPG and Infrastructure Ontario are preparing for marketing |
| **Site Description** | 700 University Ave. and parking garage at 40 Murray St. in Toronto | ~33 acres at the R.L. Hearn site in Toronto | ~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands) |
| **Buyer** | KingSett Canadian Real Estate Income Fund LP | Studios of America Limited Partner | TBD |
| **Value** | Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC) | TBD | TBD |
| **Other Considerations** | N/A | N/A | Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition |
| **Timing** | The sale closed in April 2017 | Anticipated to close in Q3 2017 | Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017 |

# 2. Other Considerations

## *Special Status for OPG to Approve International Travel*

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister requesting authority for OPG to approve international travel for its employees
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- OPG has indicated that international travel is integral to the safe and prudent operation of its business and that special status will enable efficient decision-making while lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for its pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while Darlington accounts for 45% and is expected to see increases
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

# Appendix

# 2016 Year-End Financials

| OPG Balance Sheet as at Dec 31<br>$B | 2016 |
|---|---|
| **Assets** | |
| Cash and cash equivalents | 0.2 |
| Available-for-sale securities | 0.2 |
| Receivables from related parties | 0.4 |
| Nuclear fixed asset removal and nuclear waste management funds | 0.02 |
| Other current assets | 0.9 |
| **Total current assets** | **$1.7** |
| **Net property, plant and equipment** | **$20.0** |
| **Net intangible assets** | **$0.1** |
| Nuclear fixed asset removal and nuclear waste management funds | 16.0 |
| Regulatory assets | 5.9 |
| Other long-term assets | 0.7 |
| **Other assets** | **$22.5** |
| **Total assets** | **$44.4** |
| **Liabilities** | |
| Accounts payable and accrued charges | 1.2 |
| Short-term debt and long-term debt due within one year | 1.1 |
| Income taxes payable and other current liabilities | 0.1 |
| **Total current liabilities** | **$2.4** |
| Long-term debt | 4.4 |
| Fixed asset removal and nuclear waste management liabilities | 19.5 |
| Pension liabilities | 3.0 |
| Other post-employment benefit liabilities | 2.9 |
| Other liabilities | 1.7 |
| | **$31.5** |
| **Total liabilities** | **$33.9** |
| **Equity** | |
| Equity attributable to the Shareholder | 10.4 |
| Equity attributable to non-controlling interest | 0.1 |
| **Total equity** | **$10.5** |
| **Total liabilities and equity** | **$44.4** |

| OPG Income Statement Year Ended Dec 31<br>$B | 2016 |
|---|---|
| Revenue | $5.7 |
| Fuel expense | 0.7 |
| **Gross margin** | **$4.9** |
| Operations, maintenance and administration | 2.7 |
| Depreciation and amortization | 1.3 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 0.9 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | -0.7 |
| Other expenses | 0.02 |
| **Total expenses** | **$4.2** |
| **Income before other (gains) losses, interest and income taxes** | **$0.7** |
| Other (gains) losses | -0.02 |
| **Income before interest and income taxes** | **$0.7** |
| Net interest expense | 0.1 |
| **Income before income taxes** | **$0.6** |
| Income tax expense | 0.2 |
| **Net income** | **$0.5** |
| **Net income attributable to the Shareholder** | **$0.4** |
| **Net income attributable to non-controlling interest** | **$0.02** |

Ontario

# Application and Report to Treasury Board/Management Board of Cabinet

(Refer to instructions on next page)

| 1. MINISTRY: Energy | 2. MINISTRY LOG # | 3. TB/MBC LOG # |
|---|---|---|

**4. TYPE OF REQUEST: Treasury Board General**

**5. PURPOSE OF REQUEST: The Ministry of Energy is requesting TB/MBC 1. NOTE the receipt of OPG's 2017-2019 Business Plan. 2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan 3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.**

| 6. FINANCIAL DETAILS | | ($ Millions) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Current Year | | Year 2 | | Year 3 | | Matures In | |
| | | 2016/17 | | 2017/18 | | 2018/19 | | 2019/20 | |
| | | Operating | Capital | Operating | Capital | Operating | Capital | Operating | Capital |
| A. Program Current Base | Expense | | | | | | | | |
| | Asset | | | | | | | | |
| B. Program Request (change from existing base) | Expense | | | | | | | | |
| | Asset | | | | | | | | |
| C. Available for Offset | Expense | | | | | | | | |
| | Asset | | | | | | | | |
| D. Net Impact On Program Allocation (B-C) | Expense | | | | | | | | |
| | Asset | | | | | | | | |
| E. Revenue Implications | | | | | | | | | |

| 7. IMPACT ON FTE LIMIT | Current Year 2016/2017 | Year 2 2017/2018 | Year 3 2018/2019 | Mature in 2019/2020 |
|---|---|---|---|---|
| A. Program Current Base FTE Limit | | | | |
| B. Program FTEs Request | | | | |
| C. Available FTE Offset | | | | |
| D. Net Impact on FTE Limit (B-C) | | | | |
| E. Change to Ministry Salaries & Wages Allocation (included in the Program Request ($ Millions) | | | | |

| 8. OTHER DECISION FACTORS | Y/N | EXPLANATION |
|---|---|---|
| A. Consistent with Government Priorities and Results (If Yes identify key Results) - include details in submission) | Y | MOA between Minister of Energy and OPG |
| B. Policy approval (if yes identify policy committee and date approved) | N | |
| C. Key Performance Risks (If yes provide details in submission) | N | |
| D. Impact on other Ministries (if yes - include sign-off date. Include resources impact in submission) | N | Ministries: N/A |
| E. Impact on the Fiscal Plan (if yes provide details in submission) | Y | Impact of OPG results |

**9. AUTHORIZATION /DATE**

| Signature of Minister | Day/Month/Year | Signature of Deputy Minister | Day/Month/Year |
|---|---|---|---|
| Glenn Thibeault | xxxx | Serge Imbrogno | xxxx |

## Application and Report to Treasury Board/Management Board of Cabinet

This is a general purpose form. Use it for all requests submitted to Treasury Board and Management Board of Cabinet including items delegated to the Chair of Treasury Board/Management Board of Cabinet. If the submission would result in a change in approved financial appropriations and/or full time equivalent (FTE) limits please complete Sections 6 and/or 7.

### Instructions for completing the TB/MBC Submission Template

| | |
|---|---|
| **1. Ministry** | State name (or names if it is a joint submissions). |
| **2. Ministry Log #** | Insert your Ministry Tracking log # for the submissions. |
| **3. TB/MBC Log #** | For use by TB/MBC Coordinaton Office only. |
| **4. Type of Request** | Choices may include any or a combination of the following: Financial Transaction, TBO, General, Procurement, legislation, Regulation, Order-in-Council. |
| **5. Purpose of Request** | In no more than two sentences, describe the objective of the request. |
| **6. Financial Details** | Provide financial details for the current year, outlook for the next 2 years and Maturity date.A32 |
| | **For each year of the following sections please provide applicable details for Expense, Asset, Operating and/or Capital:** |
| A. Program Current Base | Provide current base associated with the request |
| B. Program Request | Change in costs associated with the proposal. |
| C. Available for Offset | Indicate the costs that can be managed from within existing appropriations (intra or inter-ministry where applicable). |
| D. Net Impact on Program Allocation | Net impact on the Ministry's allocations. |
| E. Revenue Implications | Identify new or change in revenues that would flow into the Consolidated Revenue Fund. |
| **7. Impact on FTE Limit** | Provide staff details for the current year, outlook for the next 2 years and mature FTE impact - follows the same logic as financial details (items 6 above). For Section 7E provide the change in the salaries and wages associated with the net impact of the request (i.e. 6D) if applicable. |
| **8. Other Decision Factors** | Answer Yes or No to each of the decision factors highlighted and provide key notes on template for Minister and Deputy Minister information. Provide further details in the submission. |
| **9. Authorization /Date** | To be signed by the Minister and Deputy Minister of the requesting Ministry to confirm support for the request as submitted. Joint inter-ministry submissions require the signature of all Minister and Deputy Minster affected. Signed submission due in to the TB/MBC Coordination Office no later than 2 weeks prior t the scheduled TB/MBC meeting date. |

## Application and Report to Treasury Board/Management Board of Cabinet

Administrative Data for Current year (relates to 6B and 6C from page 1).

**TB/MBC 20**

| Vote & Item | Standard Account | Ministry Request ($ Millions) | | | | |
|---|---|---|---|---|---|---|
| | | Holdback / Release ( A) | Treasury Board Order ( B) | Increase (C) | (Decrease) (D) | Total (E=B+C+D) |
| | Salaries & Wages | | | | | |
| | Employee Benefits | | | | | |
| | Transportation & Communication | | | | | |
| | Services | | | | | |
| | Supplies and Equipment | | | | | |
| | Transfer Payments _____ | | | | | |
| | _____ | | | | | |
| | _____ | | | | | |
| | Other Transactions | | | | | |
| | Recoveries | | | | | |
| | Other (Specify) _____ | | | | | |
| | **ITEM TOTAL** | | | | | |
| | Salaries & Wages | | | | | |
| | Employee Benefits | | | | | |
| | Transportation & Communication | | | | | |
| | Services | | | | | |
| | Supplies and Equipment | | | | | |
| | Transfer Payments _____ | | | | | |
| | _____ | | | | | |
| | _____ | | | | | |
| | Other Transactions | | | | | |
| | Recoveries | | | | | |
| | Other (Specify) _____ | | | | | |
| | **ITEM TOTAL** | | | | | |
| | Salaries & Wages | | | | | |
| | Employee Benefits | | | | | |
| | Transportation & Communication | | | | | |
| | Services | | | | | |
| | Supplies and Equipment | | | | | |
| | Transfer Payments _____ | | | | | |
| | _____ | | | | | |
| | _____ | | | | | |
| | Other Transactions | | | | | |
| | Recoveries | | | | | |
| | Other (Specify) _____ | | | | | |
| | **ITEM TOTAL** | | | | | |
| **MINISTRY SUMMARY** | **Salaries & Wages** | | | | | |
| | **Employee Benefits** | | | | | |
| | **Transportation & Communication** | | | | | |
| | **Services** | | | | | |
| | **Supplies and Equipment** | | | | | |
| | **Transfer Payments** _____ | | | | | |
| | _____ | | | | | |
| | _____ | | | | | |
| | **Other Transactions** | | | | | |
| | **Recoveries** | | | | | |
| | **Other (Specify)** _____ | | | | | |
| | **MINISTRY TOTAL** | | | | | |

# MINISTRY OF ENERGY

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# TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

# ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN

**May 2017**

**CONFIDENTIAL**
**MINISTRY OF ENERGY**

**ONTARIO POWER GENERATION (OPG)**
**2017-19 BUSINESS PLAN**

## MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

## CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29 for concurrence
    - Please note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- The Minister's concurrence is subject to an appearance of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance
- The following presentation provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will ensure OPG has support from its shareholder as it implements the plan and provides clarity to the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP, these changes are not reflected in OPG's plan

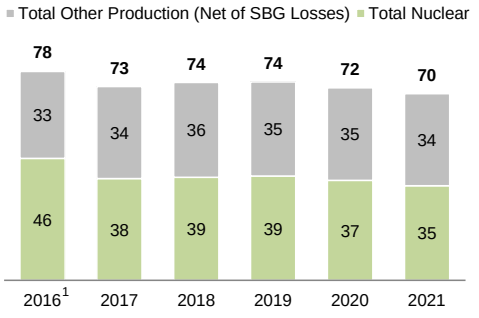
- The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed by capital infusions from the Province, and by third-party lending
- These changes are expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
- In addition, the Province's net debt position should remain unchanged

## 1. BUSINESS PLAN OVERVIEW

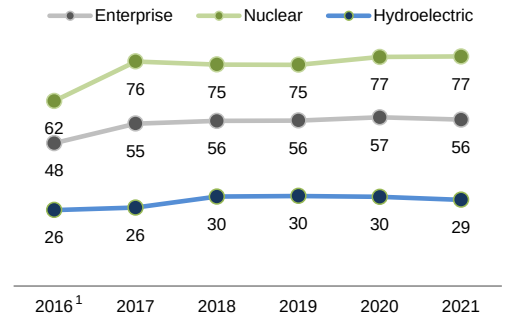
### a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 78.2 TWh in 2016
  - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
  - Also includes a partial overlap starting in 2021 between second and third unit refurbishments
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
  - Lower nuclear production due to Darlington refurbishment outages, and
  - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

**Production (TWh)**




**Total Generating Cost ($/MWh)**



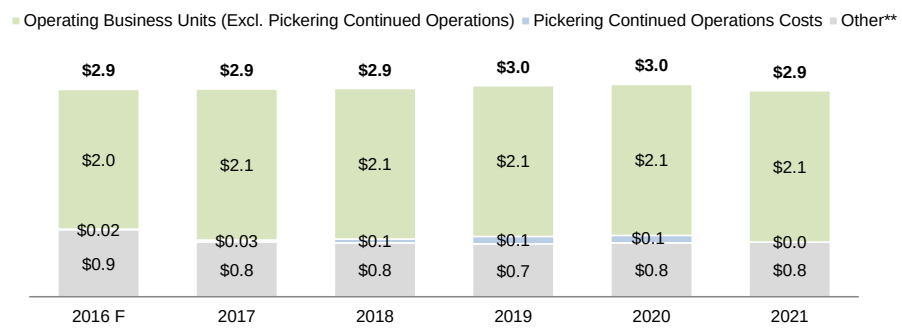

1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

### b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
    - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
    - Incremental outage and other program costs to enable Pickering continued operations
    - Partially offset by declining pension and OPEB costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

**OM&A from Ongoing Operations* ($B)**



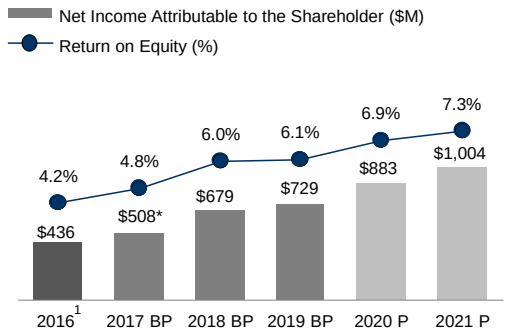

*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

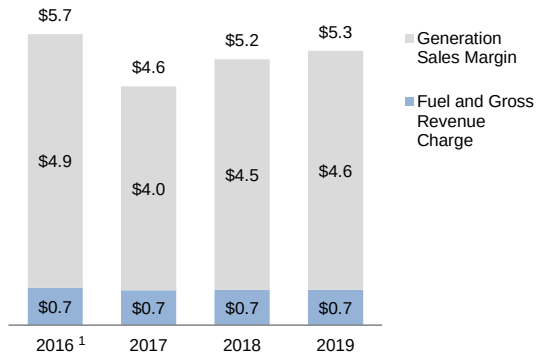
### c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, a gain on sale of OPG's head office, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher production, and earnings from oncoming stations including Nanticoke solar in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return

**Net Income ($M) and ROE (%)**




**Revenue Margin ($B)**



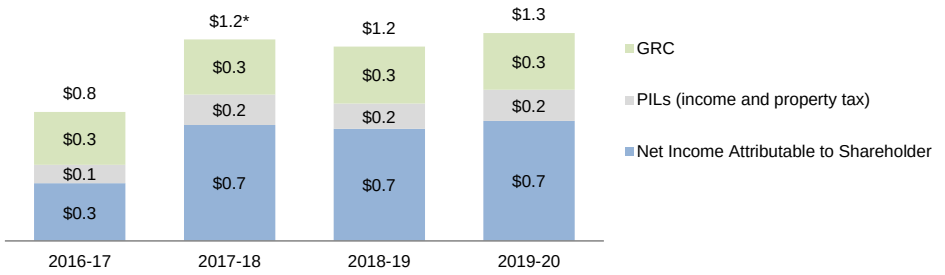

1. Actuals

*Includes extraordinary gain associated with the sale of OPG head office

## d) Shareholder Return

- Total return to the shareholder averages ~$1B over the period
- Total return to the shareholder improves over the period largely due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs) and income tax PILs are consolidated by the Ontario Electricity Financial Corporation (OEFC)
- OPG also pays a Gross Revenue Charge (GRC) and Property Taxes to the OEFC

**Total Shareholder Return ($B)**

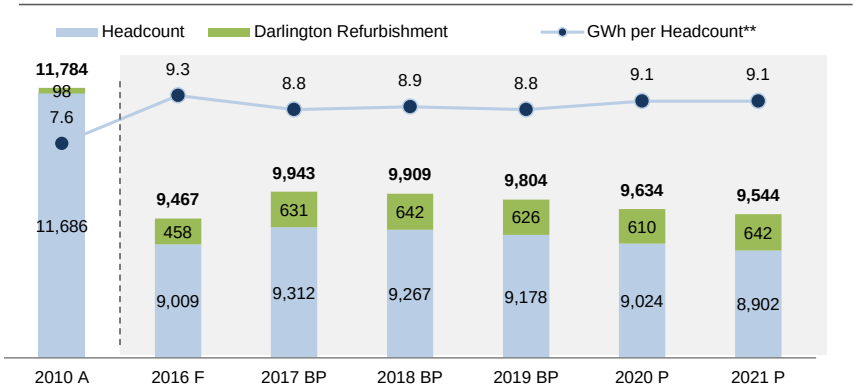



*Includes gain associated with the sale of OPG head office

### e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG has saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
    - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~60 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
    - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations

**Ongoing Operations Regular Headcount and Productivity**



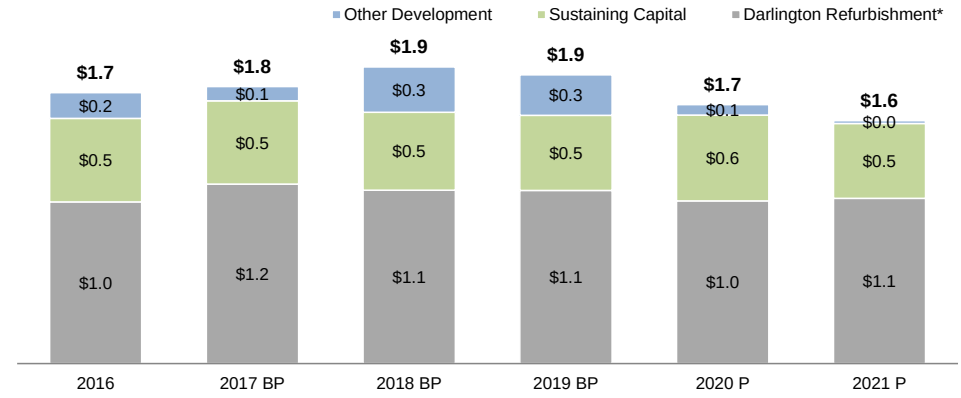

**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

### f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
    - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained

- **Sustaining Capital:** Expenditures average $570M, including:
  - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
  - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
  - Lower Mattagami upgrades in 2018 and 2019
- **Other Developments:** Investments in current and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility

**Capital Expenditure Estimates ($B)**




*Includes expenditures budgeted by Support Services

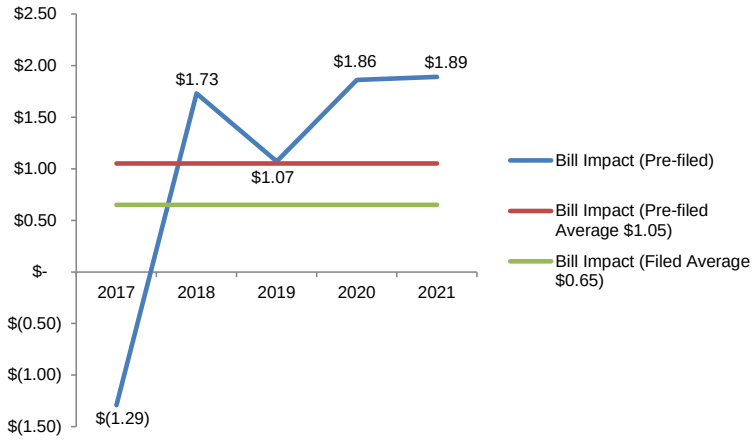
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### Rate Application

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**Comparison of Annual Bill Impact ($/Month per year)**




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| **Value** | Estimated up-front 2017-18 fiscal impact of ~$375M | TBD | TBD |
| **Other Considerations** | N/A | N/A | Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition |
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    - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
    - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG has asked that this application be included with the Ministry's submission to TB/MBC seeking concurrence with OPG's 2017-19 business plan

## RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

# APPENDIX

## OPG 2016 Year-End Financials

| OPG Balance Sheet as at Dec 31<br>$B | 2016 |
|---|---|
| **Assets** | |
| Cash and cash equivalents | 0.2 |
| Available-for-sale securities | 0.2 |
| Receivables from related parties | 0.4 |
| Nuclear fixed asset removal and nuclear waste management funds | 0.02 |
| Other current assets | 0.9 |
| **Total current assets** | **$1.7** |
| **Net property, plant and equipment** | **$20.0** |
| **Net intangible assets** | **$0.1** |
| Nuclear fixed asset removal and nuclear waste management funds | 16.0 |
| Regulatory assets | 5.9 |
| Other long-term assets | 0.7 |
| **Other assets** | **$22.5** |
| **Total assets** | **$44.4** |
| **Liabilities** | |
| Accounts payable and accrued charges | 1.2 |
| Short-term debt and long-term debt due within one year | 1.1 |
| Income taxes payable and other current liabilities | 0.1 |
| **Total current liabilities** | **$2.4** |
| Long-term debt | 4.4 |
| Fixed asset removal and nuclear waste management liabilities | 19.5 |
| Pension liabilities | 3.0 |
| Other post-employment benefit liabilities | 2.9 |
| Other liabilities | 1.7 |
| | **$31.5** |
| **Total liabilities** | **$33.9** |
| **Equity** | |
| Equity attributable to the Shareholder | 10.4 |
| Equity attributable to non-controlling interest | 0.1 |
| **Total equity** | **$10.5** |
| **Total liabilities and equity** | **$44.4** |

| OPG Income Statement Year Ended Dec 31<br>$B | 2016 |
|---|---|
| Revenue | $5.7 |
| Fuel expense | 0.7 |
| **Gross margin** | **$4.9** |
| Operations, maintenance and administration | 2.7 |
| Depreciation and amortization | 1.3 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 0.9 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | -0.7 |
| Other expenses | 0.02 |
| **Total expenses** | **$4.2** |
| **Income before other (gains) losses, interest and income taxes** | **$0.7** |
| Other (gains) losses | -0.02 |
| **Income before interest and income taxes** | **$0.7** |
| Net interest expense | 0.1 |
| **Income before income taxes** | **$0.6** |
| Income tax expense | 0.2 |
| **Net income** | **$0.5** |
| **Net income attributable to the Shareholder** | **$0.4** |
| **Net income attributable to non-controlling interest** | **$0.02** |

# MINISTRY OF ENERGY

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# TREASURY BOARD / MANAGEMENT BOARD of CABINET SUBMISSION

# ONTARIO POWER GENERATION (OPG) 2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION

**May 2017**

**CONFIDENTIAL**

**MINISTRY OF ENERGY**

**ONTARIO POWER GENERATION (OPG)**
**2017-19 BUSINESS PLAN AND SPECIAL STATUS APPLICATION**

## MINISTRY REQUEST

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

1. NOTE the receipt of OPG's 2017-2019 Business Plan.
2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.
3. APPROVE OPG's application for Special Status to Approve International Travel under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive dated January 1, 2017.

## CONTEXT

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2017-2019 to the Ministry of Energy on November 29, 2016 for concurrence
    - Note that while OPG is seeking concurrence for its three year 2017-19 business plan, the plan also includes financial projections for 2020 and 2021
- With this Business Plan OPG is also making an application for Special Status under the Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive, which allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Electricity Investment and Governance Secretariat, a unit within the Ministry of Finance and the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA)
- The following provides an overview of OPG's business plan, including:
    1. Business Plan Overview
    2. Other Considerations
- Proceeding with Provincial concurrence now will demonstrate that OPG has support from its shareholder as it implements the plan and provides clarity to

the Ontario Energy Board (OEB) as it reviews OPG's current rate application covering the 2017-2021 period

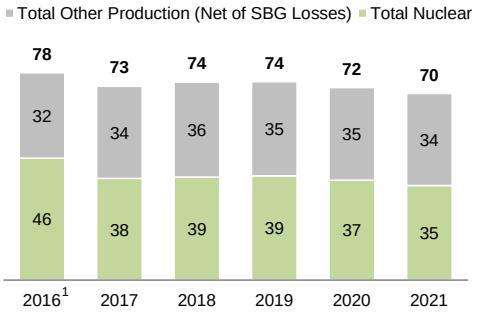
- Business plan forecasts may be affected by Ontario's Fair Hydro Plan (OFHP). Given the stage of implementation of OFHP and the timing of the receipt of the business plan in November 2016, these changes are not reflected in OPG's plan
    - The Ministry anticipates that as part of supporting the financing and administration of the global adjustment smoothing mechanism, OPG would purchase the right to future cash flows from IESO, financed partly by capital infusions from the Province, and majority by third-party lending
    - These changes are generally expected to be fiscally neutral as they would result in an increase in Provincial interest on debt, offset by increases in OPG net income
    - In addition, the Province's net debt position would remain unchanged

## 1. BUSINESS PLAN OVERVIEW

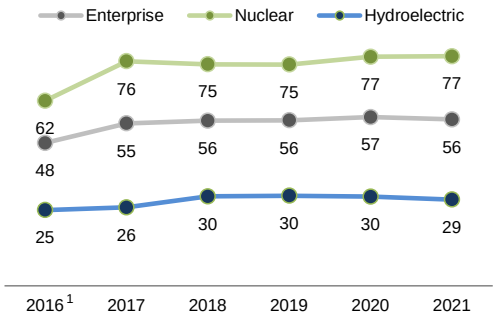
### a) Production & Total Cost of Generation

- OPG's production is expected to fall to 69.8 TWh by 2021 from 77.6 TWh in 2016
    - Reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016
    - Includes a partial overlap starting in 2021 between second and third unit refurbishments, and
    - Includes the Pickering Vacuum Building Outage (VBO) in 2021 requiring the shutdown of all units for the duration of the outage
- While OM&A remains relatively stable over the planning period (see next slide), total generating cost (TGC)* shows an increasing trend over the planning period relative to 2016, reflecting:
    - Lower nuclear production due to Darlington refurbishment outages, and
    - Increased sustaining capital spending (included in TGC) on two large hydroelectric projects, the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation

**Production (TWh)**




**Total Generating Cost ($/MWh)**



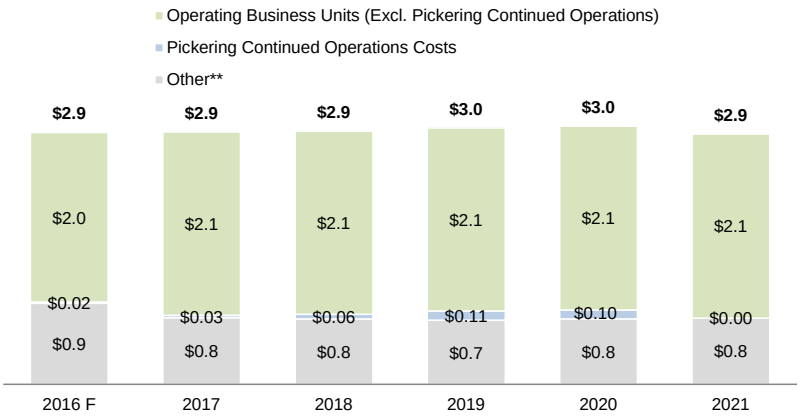

1. Actuals

*TGC = operations, maintenance and administration (OM&A) expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

## b) Operations, Maintenance and Administration (OM&A) Expenses

- Annual OM&A expenses from ongoing operations are expected to stay consistent over the plan period, averaging $2.9B per year
- Increases over 2016 are mainly attributable to:
    - Increases in business unit expenditures, including changes in nuclear outage scope at Darlington, and planned hiring to fill staffing gaps
    - Incremental outage and other program costs to enable Pickering continued operations
- These increases are partially offset by declining pension and Other Post-Employment Benefits (OPEB) costs over the period due to projected pension asset returns, increased employee contributions, and adoption of a new method for applying discount rates to determine interest components of pension costs

**OM&A from Ongoing Operations* ($B)**



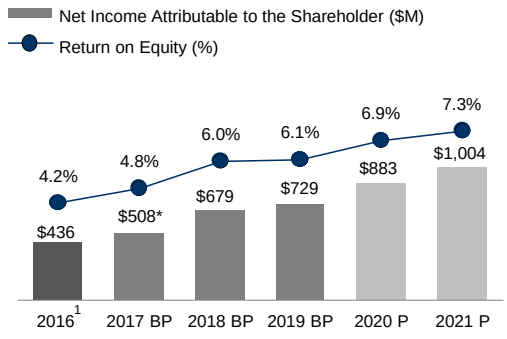

*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets

** Includes centrally held pension /OPEB costs and support services

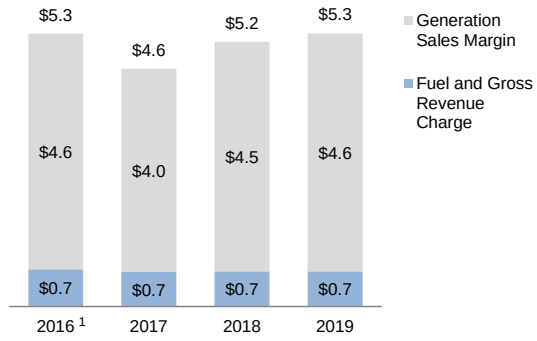
## c) Financials

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
    - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
    - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust.

**Net Income ($M) and ROE (%)**




**Revenue Margin ($B)**




1. Actuals

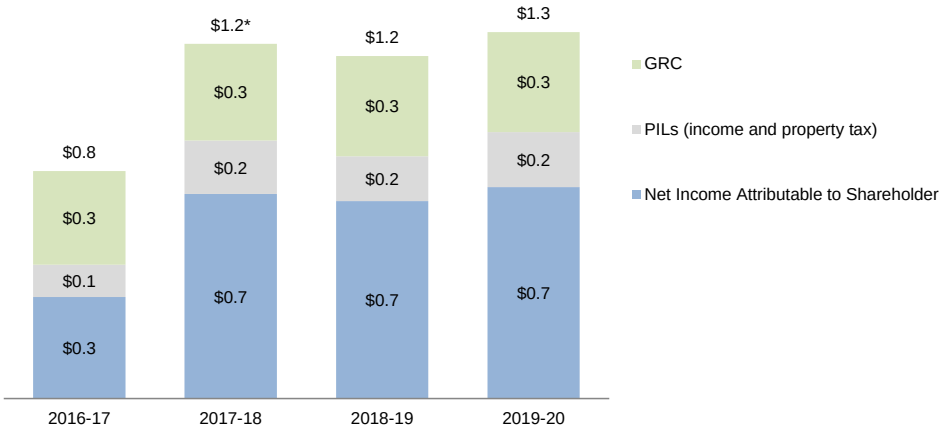
*Includes extraordinary gain associated with the sale of OPG head office

## d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
    - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]

- Return to the shareholder improves due to changes in net income, which OPG attributes to:
    - Assumed OEB rate outcomes
    - Completion of the first Darlington unit refurbishment
    - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

**Total Fiscal Revenues ($B)**




1. Aside from the water power rental portion of the GRC, paid to the CRF.

*Includes gain associated with the sale of OPG head office

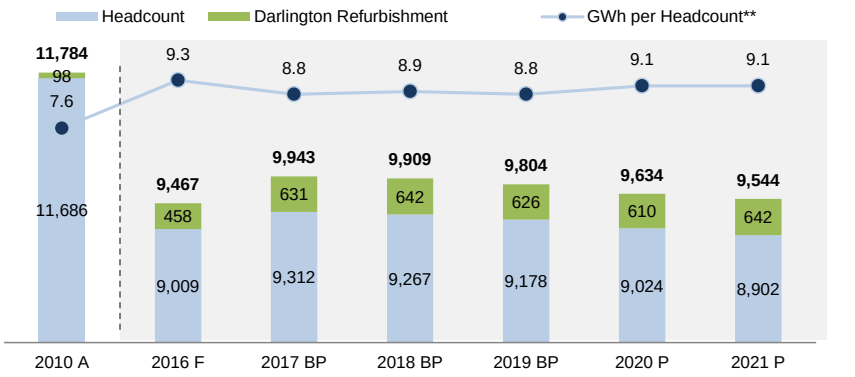
## e) Business Transformation Initiative & Labour Costs

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
    - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020

- OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021

- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

**Ongoing Operations Regular Headcount and Productivity**

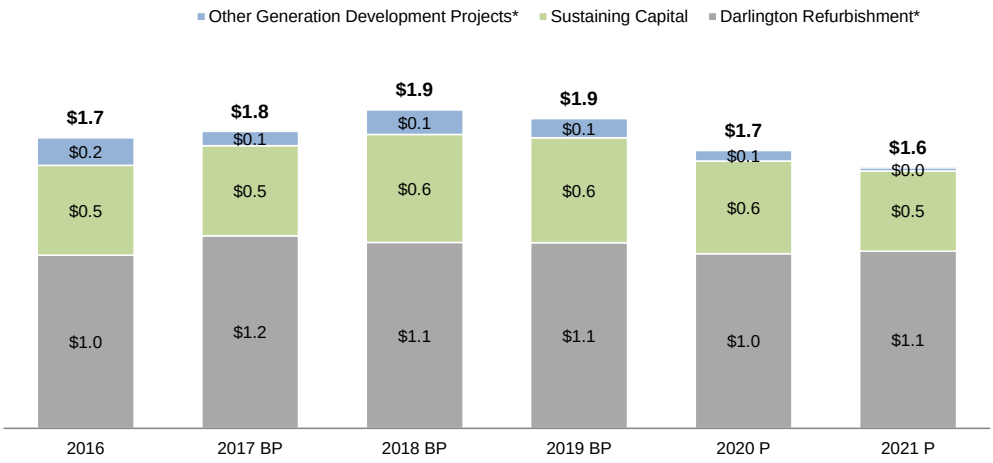



**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

### f) Operating Highlights - Projects and Capital Expenditures

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

**Capital Expenditure Estimates ($B)**



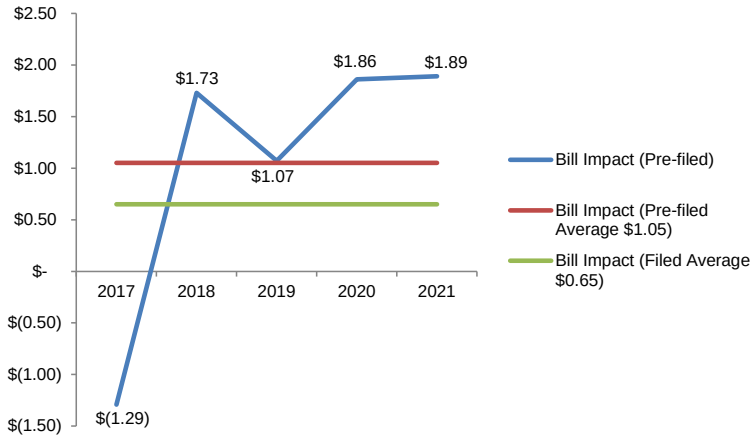

*Includes expenditures budgeted by Support Services

## 2. OTHER CONSIDERATIONS

### Rate Application

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
    - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*
- Rate-Smoothing Proposal:
    - On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
        - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
    - On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

**Comparison of Annual Bill Impact ($/Month per year)**




*Forecasted in May 2016

## Sales

| | OPG Head Office | R.L. Hearn Site | Lakeview Site |
|---|---|---|---|
| **Current Status** | Completed | Agreement Reached | OPG and Infrastructure Ontario are preparing for marketing |
| **Site Description** | 700 University Ave. and parking garage at 40 Murray St. in Toronto | ~33 acres at the R.L. Hearn site in Toronto | ~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands) |
| **Buyer** | KingSett Canadian Real Estate Income Fund LP | Studios of America Limited Partner | TBD |
| **Value** | Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC) | TBD | TBD |
| **Other Considerations** | N/A | N/A | Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition |
| **Timing** | The sale closed in April 2017 | Anticipated to close in Q3 2017 | Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017 |

## Special Status for OPG to Approve International Travel

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
    - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business

- OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
- OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
- OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
- OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
- OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation

- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

## RECOMMENDATION

The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

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Ontario

MINISTRY OF
ENERGY

# Ontario Power Generation (OPG) 2017-19 Business Plan and Special Status Application

May 2017

# Context

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  2. Other Considerations

# Context *(cont'd)*

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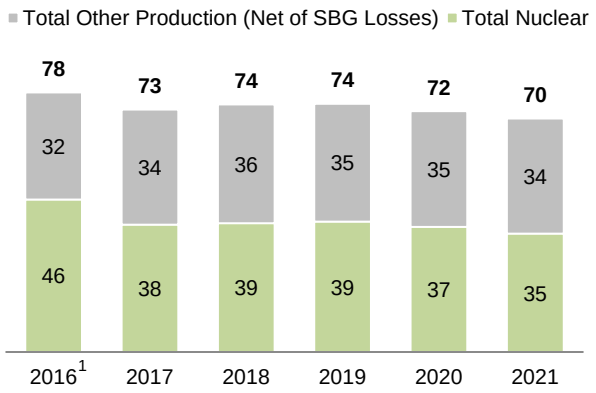
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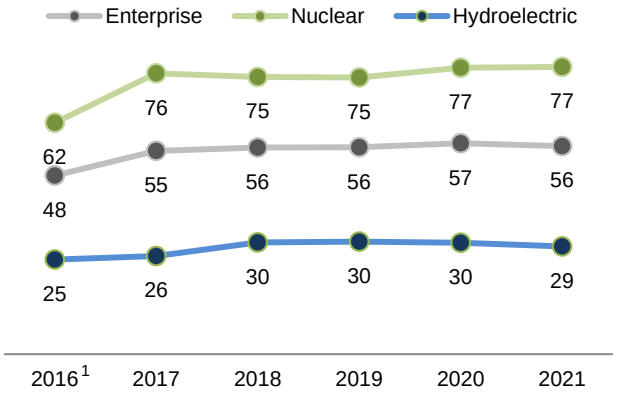
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### Production (TWh)




### Total Generating Cost ($/MWh)




1. Actuals

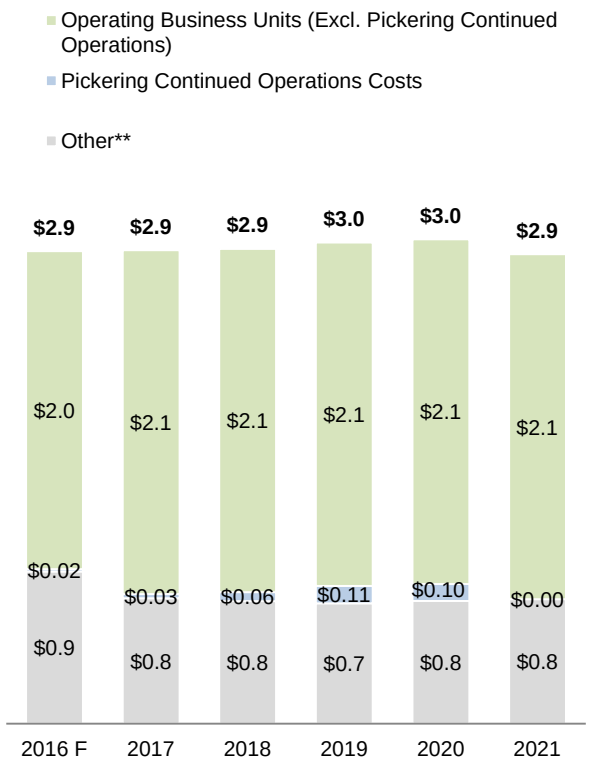
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### OM&A from Ongoing Operations* ($B)



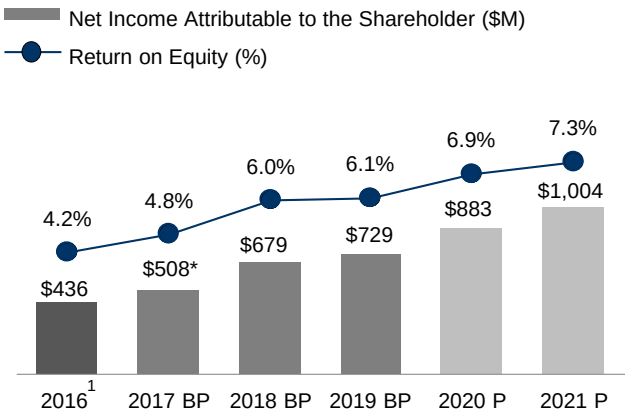

*Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs and support services

# 1. Business Plan Overview

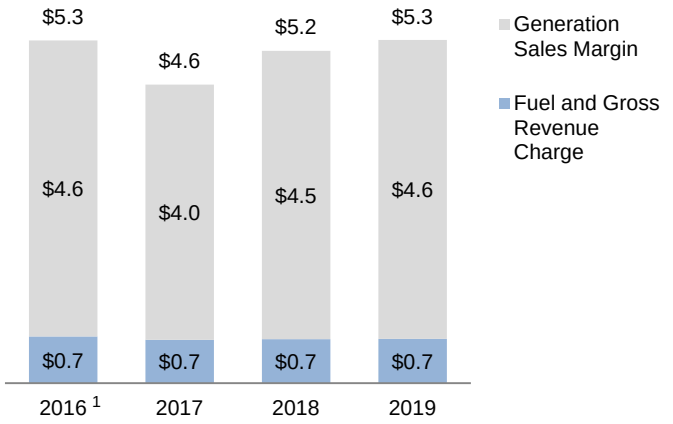
## *c) Financials*

- OPG is forecasting net income attributable to the Shareholder to reach $1B in 2021, from $436M in 2016
  - 2017 net income is forecast to increase as a result of new regulated rates, higher capitalized interest for the Darlington Refurbishment expenditures partially offset by reduced production as a result of planned outages at Sir Adam Beck I and DeCew II hydro stations
  - Net income in 2018 and 2019 is planned to increase, primarily due to higher forecast production, and earnings from Peter Sutherland Sr. GS starting in 2017 and Nanticoke solar facility starting in 2019
- As a result, return-on-equity (ROE) is estimated to increase from 4.2% in 2016 to 7.3% by 2021
- Overall, the 2017-19 Business Plan is largely unchanged relative to last year's plan in terms of commitments for Net Income, and Total Shareholder Return
- In early January 2017, subsequent to the OPG Board's approval of the 2017-2019 Business Plan, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The net gain is estimated to be $285M and will be distributed to the Trillium Trust

### Net Income ($M) and ROE (%)




### Revenue Margin ($B)




*Includes extraordinary gain associated with the sale of OPG head office

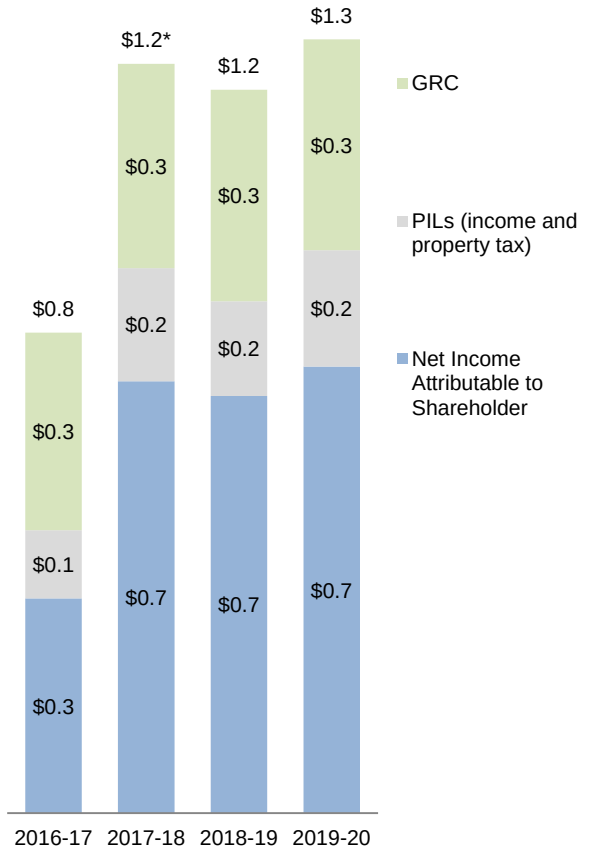
1. Actuals

# 1. Business Plan Overview

## *d) Provincial Fiscal Impacts: Shareholder Return and Payments-in-Lieu of Taxes*

- Total fiscal revenue impacts to the Province, including net income return to the shareholder and payments-in-lieu of taxes, averages ~$1B over the period
  - Provincial revenues from OPG are dedicated to servicing and paying down stranded debt and the investment cost of the Province acquiring the equity in OPG[1]
- Return to the shareholder improves due to changes in net income, which OPG attributes to:
  - Assumed OEB rate outcomes
  - Completion of the first Darlington unit refurbishment
  - Further cost efficiencies
- Net income is consolidated by the Province as Revenue from Government Business Enterprises (GBEs)
- Income tax PILs, Gross Revenue Charges (GRC) and property tax PILs paid to the Ontario Electricity Financial Corporation (OEFC) to help service and pay down stranded debt are consolidated in Public Accounts under Taxation Revenue
- OPG also pays a portion of the GRC to the Province's Consolidated Revenue Fund (CRF)

**Total Fiscal Revenues ($B)**



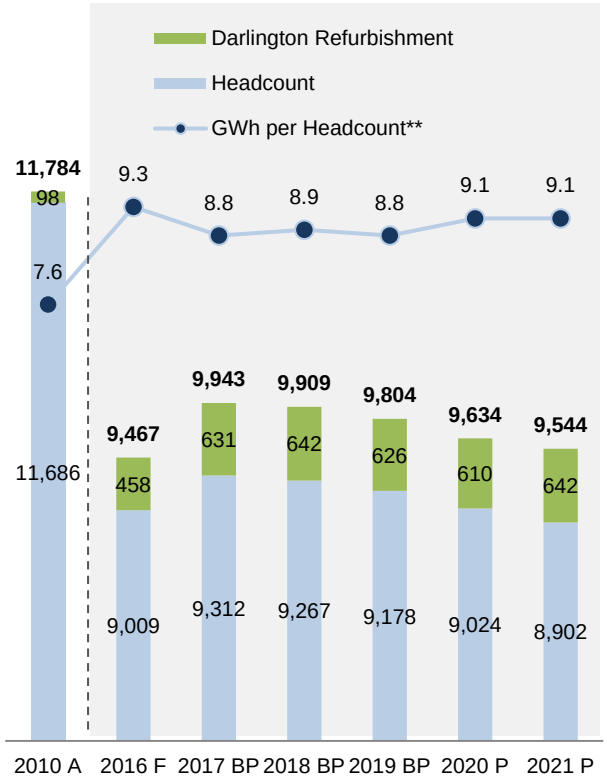

1. Aside from the water power rental portion of the GRC, paid to the CRF.
*Includes gain associated with the sale of OPG head office

# 1. Business Plan Overview

## *e) Business Transformation Initiative & Labour Costs*

- As part of a company-wide business transformation, OPG saved over $1B in costs from January 2011 to December 2016
  - Headcount has fallen from 11,686 in 2010 to a forecasted 9,009 in 2016 while GWh per headcount has increased from 7.6 to 9.3
- However, OPG is ramping up recruitment between 2016 and 2017 to fill key vacancies in certain areas (particularly in the Nuclear business unit) due to high levels of attrition from employee demographics, as well as continued Pickering operations beyond 2020
  - OPG is forecasting regular headcount to show a net increase of ~300 by the end of 2017 before gradually decreasing to 4% lower than 2017 levels in 2021
- In addition, to date OPG has hired ~95 Term employees, a new category of non-regular staff negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015
  - Intention is to add fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations, per the terms of the collective agreement

**Ongoing Operations Regular Headcount and Productivity**



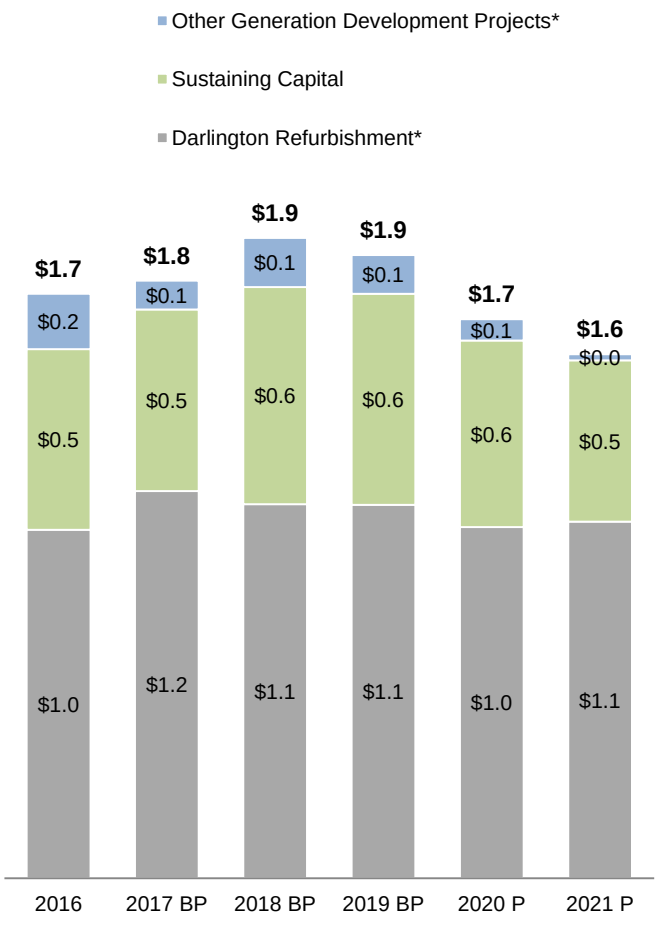

**Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017- 2021, the lower production due to the Darlington refurbishment outages

# 1. Business Plan Overview

## *f) Operating Highlights - Projects and Capital Expenditures*

- OPG continues to focus on delivery of its major projects over the plan period, including:
  - **Darlington Refurbishment**: Unit 2 is assumed to be returned to service in February 2020 with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming necessary concurrence from the Province is obtained
  - **Sustaining Capital:** Expenditures average $570M, including:
    - Nuclear expenditures unrelated to refurbishment at Darlington and costs for continued operation of Pickering
    - Regulated hydro expenditures including upgrades at Sir Adam Beck and upgrades to DeCew ll
    - Lower Mattagami upgrades in 2018 and 2019
  - **Other Generation Development Projects:** Investments in current (e.g., hydroelectric) and emerging generation technologies including solar and energy storage including construction and operation of the Nanticoke solar facility by 2019

**Capital Expenditure Estimates ($B)**




*Includes expenditures budgeted by Support Services

# 2. Other Considerations

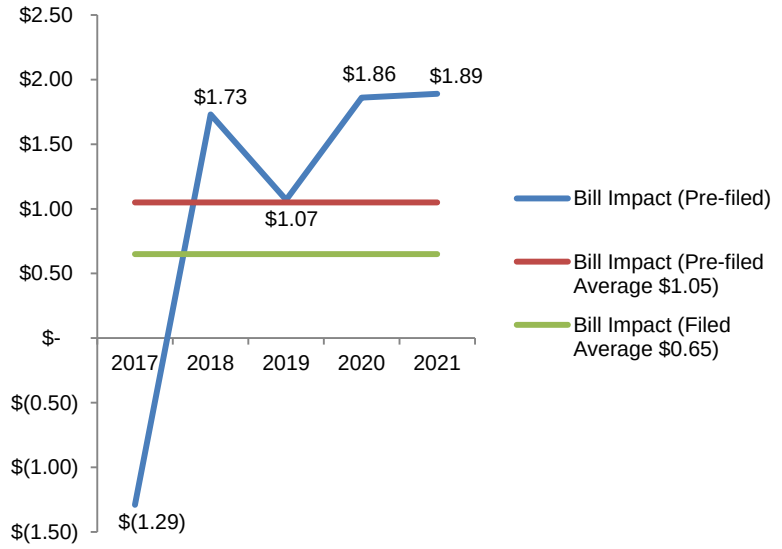
## *Rate Application*

- OPG's 2017-19 Business Plan is dependent on the outcome of its rate filing with the OEB for the five-year period from 2017-2021
- Oral hearings began February 21, 2017 with a decision expected in Q4 2017
- OPG's 2017-19 Business Plan assumes new rates are effective January 1, 2017
  - The OEB setting a later effective date would negatively impact OPG's 2017-18 fiscal year net income by ~$50-60M per month of delay*

**Rate-Smoothing Proposal:**

- On March 2, 2017 the Province filed an amendment to O.Reg.53/05, which enables OPG to smooth its rates based on OPG's weighted average hydroelectric and nuclear all-in rates (which approximates total bill impact), rather than on the basis of nuclear base rates only
  - Rate smoothing is expected to be fiscally neutral due to rate regulated accounting
- On March 8, 2017 OPG filed a revised rate smoothing proposal with the OEB, which is expected to decrease the average year-over-year annual impact on the monthly customer bill for an average consumption of 750 KWh/month from about $1.05 to 65 cents per month per year

**Comparison of Annual Bill Impact ($/Month per year)**




*Forecasted in May 2016

# 2. Other Considerations

*Sales*

| | OPG Head Office | R.L. Hearn Site | Lakeview Site |
|---|---|---|---|
| **Current Status** | Completed | Agreement Reached | OPG and Infrastructure Ontario are preparing for marketing |
| **Site Description** | 700 University Ave. and parking garage at 40 Murray St. in Toronto | ~33 acres at the R.L. Hearn site in Toronto | ~67 acres to be transferred by the purchaser to the City of Mississauga (Municipal Park Lands) and ~110 acres to be developed for mixed uses (Uplands) |
| **Buyer** | KingSett Canadian Real Estate Income Fund LP | Studios of America Limited Partner | TBD |
| **Value** | Estimated up-front 2017-18 fiscal impact of ~$375M (includes after-tax gain as well as PILs to OEFC) | TBD | TBD |
| **Other Considerations** | N/A | N/A | Negotiations with the City have been lengthy and costs to remediate/prepare site may be significant due to concerns regarding site condition |
| **Timing** | The sale closed in April 2017 | Anticipated to close in Q3 2017 | Marketing is planned to start in April 2017, pending negotiations with the City, with an anticipated closing in 2017 |

# 2. Other Considerations

## *Special Status for OPG to Approve International Travel*

- On January 24, 2017, OPG's President and CEO wrote to the Deputy Minister to provide a business case and request authority for OPG to approve international travel for its employees. In summary:
  - Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive allows agencies/organizations, for which international travel may be integral to their business, to seek TB/MBC approval for special status to ensure that the approval process does not have an undue negative effect on its ability to conduct business
  - OPG believes that international travel is integral to the safe and prudent operation of its business and having OPG's CEO approve international travel will enable more efficient decision-making while significantly lowering travel costs
  - OPG cites the importance of enabling its engagement with the international community (in particular in regards to nuclear safety), procurement activities, and investment and due diligence processes for over $30 billion in pension fund and nuclear funds
  - OPG requires a high level of international business travel at approximately 90-100 trips annually, while the Darlington Refurbishment Project accounts for 45% of OPG's international travel and is expected see increases over the 10 year life of the project
  - OPG indicated that the approval process, which took 23 days on average in 2016, delays flight bookings which results in higher costs as airlines raise fares closer to the travel date
  - OPG believes the inability to make timely commitments on events and meetings impacts employee engagement as well as its international relationships and reputation
- OPG is seeking Special Status as part of concurrence with its business plan. OPG has committed to providing semi-annual reports to the Ministry on international travel taken, and continue to be accountable for compliance with all applicable OPS directives, policies and procedures

# Appendix

# 2016 Year-End Financials

| OPG Balance Sheet as at Dec 31<br>$B | 2016 |
|---|---|
| **Assets** | |
| Cash and cash equivalents | 0.2 |
| Available-for-sale securities | 0.2 |
| Receivables from related parties | 0.4 |
| Nuclear fixed asset removal and nuclear waste management funds | 0.02 |
| Other current assets | 0.9 |
| **Total current assets** | **$1.7** |
| **Net property, plant and equipment** | **$20.0** |
| **Net intangible assets** | **$0.1** |
| Nuclear fixed asset removal and nuclear waste management funds | 16.0 |
| Regulatory assets | 5.9 |
| Other long-term assets | 0.7 |
| **Other assets** | **$22.5** |
| **Total assets** | **$44.4** |
| **Liabilities** | |
| Accounts payable and accrued charges | 1.2 |
| Short-term debt and long-term debt due within one year | 1.1 |
| Income taxes payable and other current liabilities | 0.1 |
| **Total current liabilities** | **$2.4** |
| Long-term debt | 4.4 |
| Fixed asset removal and nuclear waste management liabilities | 19.5 |
| Pension liabilities | 3.0 |
| Other post-employment benefit liabilities | 2.9 |
| Other liabilities | 1.7 |
| | **$31.5** |
| **Total liabilities** | **$33.9** |
| **Equity** | |
| Equity attributable to the Shareholder | 10.4 |
| Equity attributable to non-controlling interest | 0.1 |
| **Total equity** | **$10.5** |
| **Total liabilities and equity** | **$44.4** |

| OPG Income Statement Year Ended Dec 31<br>$B | 2016 |
|---|---|
| Revenue | $5.7 |
| Fuel expense | 0.7 |
| **Gross margin** | **$4.9** |
| Operations, maintenance and administration | 2.7 |
| Depreciation and amortization | 1.3 |
| Accretion on fixed asset removal and nuclear waste management liabilities | 0.9 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | -0.7 |
| Other expenses | 0.02 |
| **Total expenses** | **$4.2** |
| **Income before other (gains) losses, interest and income taxes** | **$0.7** |
| Other (gains) losses | -0.02 |
| **Income before interest and income taxes** | **$0.7** |
| Net interest expense | 0.1 |
| **Income before income taxes** | **$0.6** |
| Income tax expense | 0.2 |
| **Net income** | **$0.5** |
| **Net income attributable to the Shareholder** | **$0.4** |
| **Net income attributable to non-controlling interest** | **$0.02** |

Mr. Bernard Lord
Chair
Ontario Power Generation
1900-700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Lord,

Thank you for your submission of Ontario Power Generation's (OPG) 2017-2019 Business Plan ("the Plan"). We have reviewed the Plan and find it to be consistent with our government's expectations.

I support the operational and financial targets set by OPG in its business plan. We recognize the substantial cost reductions that OPG has recently achieved and expect OPG to work closely with the Province to fully realize the additional efficiencies incorporated in the Plan in a manner that is consistent with the continued safe and environmentally responsible operation of OPG's facilities.

We commend OPG on its successful start to the Darlington Refurbishment Project, a key objective of Ontario's 2013 Long-Term Energy Plan (2013 LTEP). As a priority project for the government, I expect that OPG will continue to focus on delivering the project as per the schedule and budget contained in the Release Quality Estimate approved by the OPG Board and by the government. I also expect OPG to continue to minimize project risks consistent with the nuclear refurbishment principles set out in the 2013 LTEP, and seek concurrence prior to commencing ~~subsequent unit~~ refurbishment~~s after~~of Unit ~~2~~3 ~~is successfully returned to service~~before the end of 2017.

We continue to support the planned operation of Pickering units up to 2022/2024, subject to OPG obtaining necessary regulatory approvals, as the station's output will provide reliable, cost-effective and emission-free electricity supply during the Darlington and initial Bruce refurbishments. I expect OPG to keep the Ministry apprised throughout the regulatory processes and as we proceed to update the Long-Term Energy Plan. .

I understand that the recently approved Ontario Nuclear Funds Agreement (ONFA) Reference Plan has resulted in a reduction of the estimated liabilities for future decommissioning and long-term management of waste from Ontario's nuclear fleet. With many decades of nuclear generation in the Province's future, we expect OPG to continue managing its decommissioning and waste management obligations and related segregated funds in a prudent manner. I recognize that the ONFA is based on OPG's proposed siting of a Deep Geological Repository (DGR) for low and intermediate level waste. OPG's DGR is a key component of Ontario's plans to ensure that nuclear remains the backbone of our electricity system for years to come.

I appreciate the efforts of OPG staff, management and the Board of Directors to date as we worked to develop a plan to refinance the Global Adjustment (GA). Refinancing the GA would provide significant and immediate rate relief by spreading the cost of electricity investments over the expected lifecycle of the infrastructure that has been built. OPG will be instrumental to the success of this initiative and we plan to introduce

legislation that would, if passed, enable OPG to work with the Independent Electricity System Operator (IESO) to implement this plan. I also expect to make the necessary changes to OPG's articles of amalgamation to provide the financing flexibility to implement the refinancing of the GA to meet the Province's price objectives announced on March 2, 2017.

I expect OPG to continue to keep the government informed with regard to the company's key ongoing and emerging initiatives and progress in achieving its financial and operational performance commitments. As OPG's performance directly impacts Ontario's fiscal plan, we note the importance of achieving or exceeding OPG's financial performance commitments

Consistent with Section 7 of the Memorandum of Agreement, in advance of commencing discussions for the renewal of its collective agreements with its unions, I expect that OPG shall seek advice from the Ministry on Provincial policy direction and relevant fiscal considerations affecting labour negotiations.

This letter constitutes our concurrence with OPG's Board approved 2017-2019 Business Plan as provided for under the Memorandum of Agreement between OPG and the Shareholder dated July 17, 2015.

This letter also confirms the approval of special status for OPG to approve international travel, under Section 5.3 of the Management Board of Cabinet's Travel, Meal and Hospitality Expenses Directive. OPG shall submit semi-annual reports on international travel to the Ministry of Energy, as described in the submission received from OPG's President and CEO, dated January 24, 2017.

Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

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1900-700 University Avenue
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Sincerely,

Glenn Thibeault
Minister of Energy

c: Jeff Lyash, President and Chief Executive Officer, OPG
Serge Imbrogno, Deputy Minister, Ministry of Energy
Scott Thompson, Deputy Minister, Ministry of Finance
Andrew Teliszewsky, Chief of Staff, Ministry of Energy
Ali Ghiassi, Chief of Staff, Ministry of Finance

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

**Tel: 416-592-2115**
bernard.lord@opg.com

November 28, 2016

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2017-2019 Business Plan (the Plan) which was approved by the Board at its meeting on November 10, 2016, in fulfillment of our 2015 Memorandum of Agreement.

In addition to the customary 3-year period of 2017-2019, the Plan includes a financial projection for the 2020-2021 period, similar to last year's Plan. The additional 2-year period is being provided in support of OPG's current rate application to the Ontario Energy Board (OEB) covering the 2017-2021 period. The rate application is currently in progress. The Plan reflects comments from your concurrence letter on OPG's 2016-2018 Business Plan.

***Highlights of the 2017-2019 Business Plan:***

Overall, the 2017-2019 Business Plan is largely unchanged in terms of commitments for Net Income, Total Shareholder Return and the impact to consumers.

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to the Shareholder *($ millions)* | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Total Return to Shareholder ($ millions) | 925 | 975 | 1,186 | 1,228 | 1,549 | 1,590 |
| Return on Equity *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Enterprise Total Generating Cost per MWh *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 79.2 | 72.5 | 74.0 | 74.2 | 72.0 | 69.8 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Capital Expenditures *($ millions)* | 1,739 | 1,778 | 1,905 | 1,854 | 1,662 | 1,559 |
| Headcount from Ongoing Operations | 9,009 | 9,312 | 9,267 | 9,178 | 9,024 | 8,902 |
| Average Impact of 2017-2021 Rate Application on Residential Customer's Monthly Bill | N/A | Average increase of ~$1.05/month annually for 2017-2021 | | | | |

The 2016-2018 Business Plan formed the basis of OPG's rate filing with the OEB. Many of those assumptions and inputs continue to be reflected in the 2017-2019 Business Plan, including:

- Due diligence activities in support of continued Pickering operations to 2024;
- Approved budget and schedule for the Darlington Refurbishment project;
- Outcomes of the 2017-2021 rate application effective January 1, 2017, including Hydroelectric rates increasing at less than inflation under incentive regulation and a Nuclear rate smoothing proposal reflecting amendments to O. Reg 53/05 aimed at managing customer bill impacts; and
- Use of United States Generally Accepted Accounting Principles (US GAAP) to report OPG's financial results, including for Provincial consolidation purposes.

Net Income Attributable to the Shareholder and Return on Equity improve over the period as a result of assumed OEB rate outcomes, completion of the first Darlington unit refurbishment, and further cost efficiencies. OPG's forecast contribution to the Shareholder by the Province's fiscal year is as follows:

| | Province's March 31 Fiscal Year | | | |
|---|---|---|---|---|
| *$ millions* | **2017** | **2018** | **2019** | **2020** |
| **Net Income Attributable to Shareholder** | **349** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | |
| GRC: Payable to OEFC & NPC | 321 | 332 | 344 | 343 |
| Property Tax Payable to OEFC | 15 | 18 | 19 | 19 |
| **Total Non Income Tax PILs** | **336** | **350** | **363** | **362** |
| **Income Tax PILs** | **96** | **166** | **135** | **170** |
| **Total Shareholder Return** | **781** | **1,218** | **1,176** | **1,258** |

The 2016-2018 plan assumed the OEB's decision on the rate application would be issued in the first quarter of 2017. Since then, the OEB has outlined the schedule for the proceeding such that the decision is now expected in approximately the third quarter of 2017. This means that the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016/17 fiscal year. However, the net incomes as noted above remain consistent with the previous plan.

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the 2013 LTEP, and include:

- refurbishment of the first *Darlington* unit, which commenced in October 2016;
- completing construction ahead of schedule of the *Peter Sutherland Sr.* hydroelectric station by 2017, in partnership with Taykwa Tagamou Nation;
- expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- completion of dam safety upgrade initiatives at Lower Mattagami; and
- investments in current and *emerging generation technologies* beyond the core generation portfolio, including solar and energy storage developments.

With respect to the Darlington Refurbishment project, OPG is focussed and has put in place the requisite processes and oversight organizations.

In terms of impact to customers, OPG's rate application assumed in the Plan is an increase, on average, of approximately $1.05 per month each year on a typical residential customer's monthly bill over the period to 2021, within the 2013 LTEP assumptions. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 30% to 40% below the average non-OPG cost of electricity in Ontario.

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***Critical Factors in the 2017-2019 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Outcome of Ongoing Rate Application:** OPG is well into the OEB rate application process, with an oral hearing scheduled in mid February 2017. This application is transformational to OPG. Moving to a 5-year rate term, transitioning to incentive regulation for Hydroelectric assets, reflecting the continued operations of Pickering to 2024 and the plans to refurbish and return to service Unit 2 at Darlington, while implementing a rate smoothing proposal brought about through regulation change, and managing the uncertainty of outcomes related to the OEB's generic proceeding on the recovery of pension and OPEB costs are all significant events. While OPG is confident in the evidence it has submitted and the more open and collaborative approach it has adopted through the regulatory process, the outcome of this complicated and multifaceted application is subject to risk and cannot be predicted with certainty. OPG believes that the outcomes reflected in the Plan are realistic.

- **Delay in Effective Date of OPG's Rates:** Consistent with the previous plan, the 2017-2019 Business Plan assumes that new regulated rates from the application process are effective at the start of 2017. It is within the OEB's authority to set a later effective date, which would have a negative impact of approximately $60 million per month to OPG's net income for the 2017/18 fiscal year.

- **Pickering Continued Operations:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering units to the 2022/2024 period with CNSC approval. The IESO and OPG conducted separate economic evaluations, both of which concluded that extending Pickering has value to Ontario electricity consumers of approximately $600 million. Continuation of Pickering operations also results in a lower smoothed OPG nuclear rate over the Darlington refurbishment period for consumers and employment for several thousand people in and around Pickering while reducing $CO_2$ emissions. A requirement of the next license renewal hearing for Pickering in 2017 will be confirmation from OPG that the Pickering units will operate to 2022/2024 and the filing of our plan for closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on consumer prices.

- **Risk of Adopting International Financial Reporting Standards (IFRS):** OPG has been working with the Province on the possibility of consolidating results using IFRS as required by the Auditor General of Ontario. Under IFRS, OPG's financial results would be subject to considerably increased volatility, due to IFRS impacts on nuclear liability accounting. OPG also may not be able to establish deferral accounts, including several billion dollars related to nuclear rate smoothing which could result in immediate write-offs. These factors could effectively eliminate OPG's net income in the future. OPG continues to work with the Province on this issue. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

- **Executive Compensation Framework:** As a result of compensation restraint legislation and regulations over the past several years, the Company has been unable to make changes needed to remain competitive and to ensure OPG can continue to attract, align and retain the leadership skills and talent required to operate our plants and deliver successfully on projects such as the $12.8 billion Darlington Refurbishment. OPG has worked with external compensation consultants to develop an Executive Compensation Framework (ECF) targeted at the 50$^{th}$ percentile of market peers that would better position OPG to attract, retain and align the necessary leadership talent. With the 10-year Darlington Refurbishment project moving into execution, it is critical that OPG's ECF be in place for the start of 2017. The Ministry's continued active support for OPG's ECF, and help in securing an amendment to Regulation 304/16 in recognition that there are no public sector comparators for OPG's Authorized Nuclear segment, as well as an application to the President of the Treasury Board for permission to use private and international comparators, is very much appreciated.

  The ECF includes medium term incentives, which are 100% pay at risk. For the 2017-2019 cycle, OPG has established the following medium term measures and targets:

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- Return on Equity (%),
- Total Generating Cost ($/MWh) and
- Progress in execution of Darlington Refurbishment Unit 2.

These measures were selected because they are based on the 2017-2019 Business Plan, are self-funding, support the long term health of OPG, and contribute to sustained growth in shareholder value. It is important that, come January 1, 2017, OPG be able to roll out these measures and targets across the Company.

- **Sale of Head Office:** The process from the sale of the 700 University Avenue and 40 Murray Street properties has commenced. The intent of the Plan is to transfer the full portion of the proceeds equal to the after tax accounting gain on sale to the Province, as directed by the Shareholder. However, should the OEB determine that a portion of the proceeds is to be disbursed to ratepayers instead, the value of the gain transferrable to the Province would be reduced correspondingly.

- **Nuclear New Build:** In line with the 2013 LTEP, the Plan includes investments to continue to maintain the site preparation license granted by CNSC related to the New Nuclear option at the Darlington site. As part of the 2017 LTEP, OPG encourages the Province to develop a dialogue with the Federal government and other provinces on the role for New Nuclear in meeting climate change targets. OPG and Ontario have an opportunity to participate in the deployment of new nuclear technologies with partners willing to invest here with the right signals. This Plan anticipates the investment of funds to begin initial planning and preparation activities related to assessing the feasibility of bringing New Nuclear forward as a longer term option in the Province's energy mix.

- **Credit Rating:** Successful execution of major initiatives and an OEB rate outcome consistent with the 2017-2019 Business Plan should ensure that OPG maintains its investment grade credit rating. However, decisions or events with sustained negative financial consequences over the Plan period would stress the credit assessment metrics.

## ***OPG Could Provide Greater Value to the Shareholder and Customer***

You and the Premier have asked for OPG's assistance in keeping electricity prices as low as possible, and to unlock value from OPG to help the Province address its priorities. OPG is well positioned to do both with Shareholder support for four proposals that put OPG on a more commercial footing. These proposals are not assumed in the 2017-2019 Business Plan, but have the potential to deliver enhanced customer and shareholder value over the long term. We are including them here to ensure that the Ministry is aware of them and look forward to a meaningful dialogue.

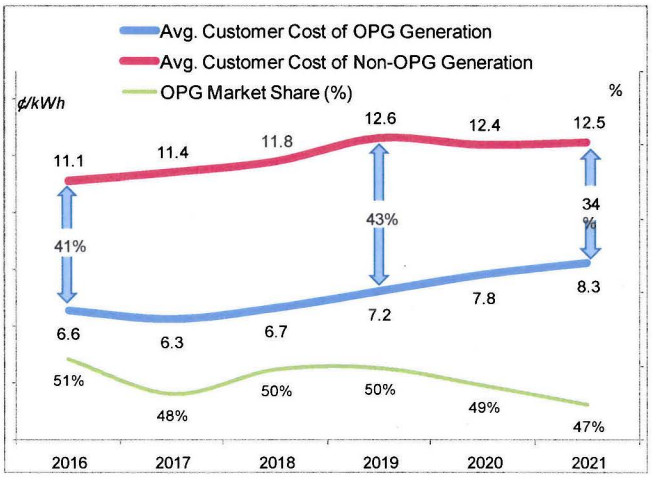
1) *Align OPG's Capital Structure with the OEB*
If OPG's capital structure was in line with the OEB deemed capital structure that OPG has proposed in its current rate application of 51% debt and 49% equity, with this plan, OPG would achieve the following higher ROE levels:

**ROE Assuming OEB Capital Structure**

| | Business Plan | | | Projection | |
|---|---|---|---|---|---|
| | **2017** | **2018** | **2019** | **2020** | **2021** |
| Return on Equity Assuming OEB's Deemed Capital Structure *(%)* | 5.7% | 6.8% | 7.0% | 8.2% | 8.9% |

2) *Invest in Assets to Continue to Mitigate Prices*
Achieving a higher ROE would allow OPG to leverage its expertise in generation and re-invest to maximize generation from existing assets and invest in new unregulated assets to replace 3000 MW of generation from the closure of the Pickering generating station. OPG's market share has declined by about 20% with coal closure, and will shrink further with the closure of Pickering. By replacing those megawatts, OPG would direct a portion of the additional capital into suitable investment options in order to increase the Shareholder's value of the Company.

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In addition, OPG would be able to maintain a critical size and continue to mitigate prices for customers some 30% to 40% below other generators. Working with the Shareholder OPG would explore options for investments in the near term, ensuring that these investments provide value to customers and the Province and do not distract from our current Plan. OPG has already successfully made more than $5 billion in investments in clean, renewable technologies undertaken over the past decade. Those investments have not only supported Ontario's climate change initiatives but have generated returns that represent a notable share of OPG's net income. We can do more.

3) *Pay Dividends to Fund Government Priorities*

OPG has also proposed the establishment of a dividend program tied to key business outcomes, including a successful OEB rate outcome and Darlington Unit 2 refurbishment that could return to the Shareholder $2.4 billion, which the Province could use to target its priorities – this could be lowering prices for electricity or investing in infrastructure.

*Illustrative Dividend Program – not in the 2017-2019 Business Plan*

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|
| Leverage to 51% | Debt Ratio | 34% | 39% | 40% | 42% | 42% | 41% | |
| | Net Income Attributable to Shareholders ($M) | 438 | 494 | 659 | 694 | 832 | 938 | 4,056 |
| | ROE target | 4.2 | 4.9 | 6.1 | 6.3 | 7.4 | 8.0 | |
| | Dividend | 0 | 620 | 400 | 500 | 400 | 500 | 2,420 |

Dividend payments would assist OPG in achieving a more balanced capital structure and would also provide for a more predictable and steady future cash flow. As shown in the table above, ROE improves as the leverage transitions toward the deemed capital structure used by the OEB. On this path, a 9% ROE of would be achieved post completion of Darlington Refurbishment .

4) *Use OPG Public Debt to Reduce Provincial Debt*

To establish the dividend program and to drive greater commercial behaviours to the benefit of customers and the Shareholder, OPG has proposed to replace financing from the Ontario Electricity Financial Corporation with a public financing strategy for a portion of OPG's corporate debt. This debt program could start small and grow over time as OPG produced results. OPG could remove approximately $6 billion from the Province's debt by 2021 which includes the refinancing of maturing debt and future additional funding requirements. OPG has had significant success with $2.2 billion in various project financing in external markets. Additional benefits include supporting the OEB's capital structure, driving a level of discipline and commercial orientation within the Company, accessing new debt investors and supporting OPG's ability to retain the exemption from the Ontario Securities Commission to remain on US GAAP.

In closing, OPG's 2017-2019 Business Plan and the financial projection for the 2020-2021 period set ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG will achieve this while focussed on the successful execution of Darlington refurbishment. . We look forward to further dialogue on the proposals we have described above that are not currently in the Business Plan but could enhance customer and shareholder value.

Sincerely,

Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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November 10, 2016

# OPG's 2017-2019 BUSINESS PLAN

## DECISION REQUIRED

The purpose of this submission is to seek the Board's approval of OPG's 2017-2019 Business Plan, including a financial projection for the 2020-2021 period. Upon Board approval, the business plan will be submitted to the Shareholder for review and concurrence in accordance with the Memorandum of Agreement between the Shareholder and OPG.

## ISSUE

OPG's 2017-2019 Business Plan implements the Company's strategic objectives by setting out performance targets and resource levels associated with meeting key business outcomes over the next several years. The business plan includes the budget for the 2017 year, which establishes the operational and financial control base against which actual results will be measured.

The business plan supports OPG's 5-year hydroelectric and nuclear rate application to the Ontario Energy Board (OEB) filed in May 2016. The rate application covers the 2017-2021 period and, for the nuclear operations, was based on the forecast of costs and production from the 2016-2018 Business Plan. The 2016-2018 Business Plan was approved by the Board in May 2016 and included a financial projection for 2019-2021. The 2017-2019 Business Plan will be used to update the rate application for material plan-over-plan changes and therefore includes a financial projection for 2020-2021. The OEB's decision on OPG's rate application is expected during the third quarter of 2017. The 2017-2019 Business Plan assumes that new regulated rates are made effective January 1, 2017.

## ANALYSIS

### Overview

OPG's business plan is focused on increasing value to the Shareholder, while continuing to act as a mitigator for customer price increases and supporting provincial policy objectives focused on the decarbonisation of the power sector and the broader economy. The plan meets the objectives of Ontario's 2013 Long-Term Energy Plan (LTEP). Future business plans will reflect any changes from the updated LTEP expected to be issued in 2017.

As OPG's operating and regulatory environment has not changed substantially during 2016, the objectives and results of the 2017-2019 Business Plan are consistent with the 2016-2018 Business Plan. In particular, the business plan continues to reflect resource and outage plans in support of achieving safe and reliable operations at Pickering to 2024 and successful execution of the Darlington refurbishment, in line with the approved budget and schedule including the Unit 2 cost estimate approved by the Board in August 2016. The plan also reflects OPG's efforts to close the staffing gap in key areas through resourcing strategies including selective hiring, while continuing to leverage attrition in other areas.

Consistent with the previous plan, the 2017-2019 Business Plan projects net income growing to ~$730 million in 2019 and ~$1 billion in 2021. This reflects regulated rate increases consistent with OPG's May 2016 rate application, on the basis of a custom incentive regulation approach with rate smoothing for the nuclear operations and an incentive ratemaking formula for the hydroelectric operations. The rate application results in average increases of ~0.7% or ~$1.05 per month annually on a typical residential customer's monthly bill, with the overall customer cost of OPG's generation continuing to track considerably below that of other generators in Ontario. Management believes that the forecast credit metrics and operating cash flow levels in the plan that result from the proposed rate increases should continue to

support OPG's current investment grade credit rating. The execution of the business plan will allow OPG to contribute ~$3.4 billion in earnings and taxes to the Shareholder over the 2017-2019 period.

The plan reflects the completion of the Peter Sutherland Sr. hydroelectric generating station (GS) in 2017 and the Nanticoke solar facility in 2019, both of which will contribute positively to earnings. The plan also reflects the estimated impact of the 2017 Ontario Nuclear Funds Agreement (ONFA) Reference Plan update, which is subject to approval by the Minister of Finance. The updated reference plan will reduce customer rate impacts, and improve operating cash flow by reducing segregated fund contributions. In addition, the plan assumes closing of the sale of OPG's head office property in the second quarter of 2017, with the portion of the proceeds equal to the after-tax accounting gain on the sale transferred to the Province, as directed.

Return on equity (ROE) is projected to increase from 4.2% in 2016 to 7.3% by 2021, but continues to fall short of the OEB-allowed regulated rate of return of ~9%. Through ongoing discussions with the Shareholder, OPG has developed a strategy to migrate the capital structure to reduce equity and increase debt, with a view to pursuing a public debt offering strategy in conjunction with a focused growth strategy. This would help OPG to move toward a 9% ROE. The strategy is subject to the Shareholder's concurrence, and therefore is not yet reflected in the business plan. As such, OPG's planned debt ratio remains in the range of approximately 31% to 37%, well below OEB-approved levels of over 50%. As shown below, if OPG's actual capital structure reflected the deemed debt ratio of 51% proposed in OPG's rate application, ROE of ~9% would be achievable by the end of the planning period.

The business plan is highly dependent on the outcome of OPG's OEB rate application and OEB decisions related to the recovery of pension and other post-employment benefit (OPEB) costs on an accrual basis. Different regulatory outcomes from those assumed in the plan could significantly lower net income, cash flow, and returns to the Shareholder, leading to higher borrowing requirements and increased risk to OPG's credit rating. This may in turn necessitate curtailment of project or other expenditures. In particular, the plan assumes that new regulated rates pursuant to the rate application are made effective as of January 1, 2017. A delay in this effective date could have significant adverse impacts on 2017 net income and future cash flow, largely due to the nuclear generation shortfall relative to existing rates, as a result of Darlington Unit 2 being offline for refurbishment. The plan also assumes that the OEB provides necessary assurance over future recovery of differences between pension and OPEB accrual and cash amounts, and associated income tax impacts.

Highlights of the 2017-2019 Business Plan, including the financial projection for the 2020-2021 period, are as follows:

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to the Shareholder *($ millions)* | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Return on Equity *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Enterprise Total Generating Cost per MWh *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 79.2 | 72.5 | 74.0 | 74.2 | 72.0 | 69.8 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Capital Expenditures *($ millions)* | 1,739 | 1,778 | 1,905 | 1,854 | 1,662 | 1,559 |
| Headcount from Ongoing Operations | 9,009 | 9,312 | 9,267 | 9,178 | 9,024 | 8,902 |
| Average Impact of 2017-2021 Rate Application on Residential Customer's Monthly Bill | N/A | Average increase of ~$1.05/month annually for 2017-2021 | | | | |

If OPG's actual capital structure was in line with the OEB deemed capital structure of 51% debt and 49% equity proposed in the rate application, OPG would plan to achieve the following higher ROE levels:

| | Business Plan | | | Projection | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Return on Equity Assuming OEB's Deemed Capital Structure *(%)* | 5.7% | 6.8% | 7.0% | 8.2% | 8.9% |

**Key Assumptions and Risks**

- Planned activities carried out over the 2017-2020 period successfully enable Pickering continued operations beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operations beyond 2020 would result in a reduction to planned generation revenues and cash flow and the advancement of employee severance and station decommissioning expenditures. Extending Pickering operations has a moderating effect on OPG's nuclear rates.
- The Darlington refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.
- New regulated rates are effective January 1, 2017. An OEB decision that delays this effective date would result in a ~$50 million to $60 million reduction in net income per month. In addition, new rates established by the OEB that are lower than those requested by OPG may not provide for recovery of all costs of OPG's regulated operations or may not allow for an appropriate rate of return.
- Pension and OPEB costs allowed in the 2017-2021 nuclear rates are limited to cash amounts, with the difference between accrual and cash amounts (for nuclear and hydroelectric) continuing to be recorded in a deferral account. The OEB provides necessary assurance over future recovery of these amounts, including associated taxes, through the ongoing generic proceeding on this issue or otherwise. An OEB decision that leads to a write-off of the deferral account balance would result in material net income reductions of over ~$600 million over the planning period.
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations could adversely impact the successful execution of these projects and other strategic imperatives.
- OPG continues to report its financial results in accordance with United States generally accepted accounting principles (US GAAP) and the OEB continues to rate regulate OPG on that basis. Adoption of International Financial Reporting Standards (IFRS), either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements using US GAAP or the Shareholder's requirement to consolidate OPG's results under IFRS, is expected to cause significant volatility in OPG's net income compared to US GAAP. Currently, IFRS does not adequately address a rate regulated environment.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2017-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2. A discussion of the 2017-2019 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Operational Excellence

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost. The business plan reflects funding and staffing levels aimed at achieving top performance at the Darlington nuclear station, maximizing the value of the Pickering nuclear station by continuing its safe and reliable operation to 2024, and maintaining strong cost-effective performance at OPG's hydroelectric and thermal facilities. Performance targets for safety and reliability over the planning period will continue to drive operational excellence.

| Total Generating Cost* | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *($/MWh)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Enterprise | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Nuclear | 63.2 | 75.6 | 74.6 | 74.5 | 77.1 | 77.3 |
| Hydroelectric | 25.1 | 26.4 | 30.1 | 30.3 | 30.0 | 29.0 |

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately $55/MWh to $57/MWh over the 2017-2021 period. The increase in the TGC over the planning period reflects lower nuclear production levels as a result of the Darlington refurbishment outages, as well as higher capital expenditures due to two large hydroelectric projects – the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging 88.3% per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

**Production**

Total planned OPG production ranges from 72.5 TWh to 74.2 TWh per year over the 2017-2019 period, down from 79.2 TWh forecast in 2016 and declining to 69.8 TWh in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:

- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;

- Initial increase in the forced loss and planned outage days expected at the Darlington station as the first refurbished unit returns to service in early 2020; and
- Pickering VBO in 2021 requiring the shutdown of all units for the duration of the outage.

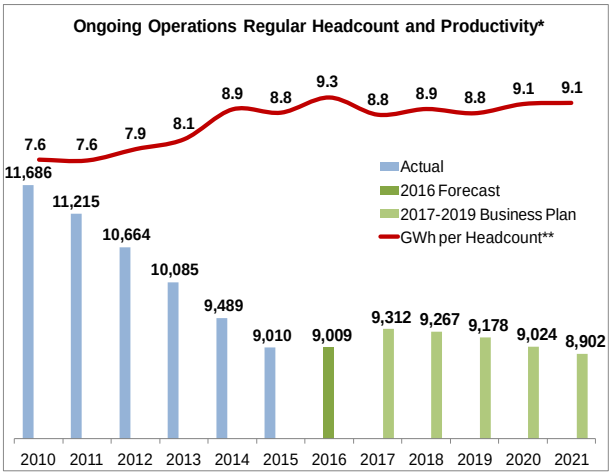
The following are the main drivers of the forecast hydroelectric production for the period:

| Production (TWh) | Forecast 2016 | Business Plan 2017 | Business Plan 2018 | Business Plan 2019 | Projection 2020 | Projection 2021 |
|---|---|---|---|---|---|---|
| Darlington | *25.8* | *19.1* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *20.1* | *19.1* | *19.2* | *19.4* | *19.6* | *18.8* |
| Total Nuclear | 45.9 | 38.1 | 38.5 | 39.0 | 37.4 | 35.4 |
| Regulated Hydroelectric | 30.5 | 31.2 | 32.2 | 32.0 | 31.2 | 30.8 |
| Contracted Generation Portfolio | 2.7 | 3.1 | 3.3 | 3.2 | 3.4 | 3.5 |
| **Total Production (Net of SBG Losses)** | **79.2** | **72.5** | **74.0** | **74.2** | **72.0** | **69.8** |
| Regulated Hydroelectric SBG Losses | 4.0 | 1.3 | 1.0 | 0.9 | 0.3 | 0.3 |
| Contracted Plant SBG Losses | 0.4 | 0.3 | 0.3 | 0.3 | 0.2 | 0.1 |
| Total SBG Losses | 4.5 | 1.7 | 1.2 | 1.2 | 0.5 | 0.4 |

- Anticipated improvement in surplus baseload generation conditions during the planning period, largely driven by nuclear refurbishment outages;
- A major unit overhaul outage at the DeCew II GS in 2017;
- A series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over 2017-2019;
- Outages at the Sir Adam Beck I GS to rehabilitate the forebay and crossover canal in 2020 and the power canal liner over 2020 and 2021; and
- Production from the newly online Peter Sutherland Sr. GS starting in 2017 and lower production from the Lower Mattagami units in 2016 due to transmission system unavailability and an extended planned outage.

**Headcount**

The downsizing efforts from OPG's Business Transformation initiative have been successful in achieving significant attrition-based headcount reductions across the organization since 2011, with cumulative savings from the reductions reaching $1 billion in 2016. However, continuing high levels of attrition reflecting employee demographics are necessitating increased hiring to fill key vacancies in certain areas (particularly in the Nuclear business unit). To address this gap and in light of the decision to pursue extended Pickering operations beyond 2020, OPG has modified resourcing plans and staffing models, taking into consideration the current need for qualified staff while seeking to minimize the financial impact of future downsizing programs associated with the planned Pickering end of life in 2024.




* Excludes Darlington refurbishment headcount

** Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017 - 2021, the lower production due to the Darlington refurbishment outages

Through these efforts, OPG has hired ~500 regular (full-time) employees (excluding Darlington refurbishment) between January 2016 and the end of September 2016, and is actively continuing to ramp up recruitment and on-boarding efforts to attract the necessary talent. In addition, to date OPG has hired ~60 Term Employees, a new category of non-regular employees negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015, with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. OPG is targeting to bridge the remaining staffing gap in 2017 by filling open positions, which will increase year-end 2017 regular headcount from ongoing operations by approximately 300, compared to 2016. While planned positions are being filled, work programs are being managed through the selective use of temporary resources and overtime.

After 2017, planned staffing levels from ongoing operations begin to decrease gradually. By the end of 2021, headcount from ongoing operations is expected to be about 100 lower than at the end of 2016 and

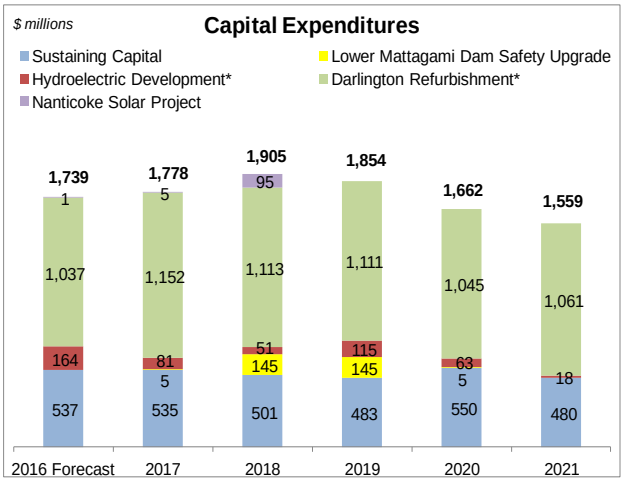
about 400 lower than at the end of 2017. These reductions reflect efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020. Employee productivity, as measured by GWh per headcount, remains relatively stable during the planning period.

The Darlington refurbishment headcount peaks at about 640 during the planning period, compared to about 460 at the end of 2016. This headcount is not considered part of ongoing operations.

## Project Excellence

Asset base growth through development or acquisition is a key element to achieving increased profitability and ROE levels. OPG continues to focus on delivering projects safely, on time, on budget and with high quality. In line with the 2013 LTEP, OPG's capital program is focused on the continued efficient utilization of existing generation assets through sustaining expenditures, the refurbishment of the Darlington units, development of new and existing hydroelectric sites, and the pursuit of other renewable energy opportunities. The upcoming 2017 LTEP may or may not support OPG's pursuit of additional investment opportunities.

Total annual capital expenditures range between ~$1.8 billion and ~$1.9 billion per year over the 2017-2019 period and between ~$1.6 billion and ~$1.7 billion in 2020 and 2021. This includes Darlington refurbishment expenditures of between ~$1.0 billion and ~$1.2 billion per year in line with the Board-approved Unit 2 cost estimate, ~$45 million for the completion of the Peter Sutherland Sr. GS for in-service in 2017, and ~$100 million for the construction of the Nanticoke solar facility by 2019.



* Includes expenditures budgeted by Support Services

The first refurbished Darlington unit, Unit 2, is assumed to be returned to service in February 2020 per the high-confidence project schedule, with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming any necessary concurrence from the Province is obtained. The planned in-service amount associated with the return to service of Unit 2 is $4.8 billion in February 2020, including costs incurred during the planning phase of the project.

Total sustaining capital expenditures average ~$570 million per year over the 2017-2021 period. This includes Nuclear expenditures in the order of ~$300 million per year to 2020, decreasing to ~$245 million by 2021 as regulatory programs are completed and non-refurbishment capital project work at Darlington is temporarily reduced while two units undergo refurbishment. Pickering expenditures decline over the period in line with the planned end of life in 2024.

Excluding the Sir Adam Beck I GS power canal liner rehabilitation project, regulated hydroelectric sustaining capital expenditures over the 2017-2021 period average ~$130 million per year. This includes a number of projects aimed at maintaining and enhancing availability and reliability of OPG's renewable fleet, including:

- The completion of the Sir Adam Beck Pump GS reservoir rehabilitation in 2017;
- The overhaul and upgrade of the DeCew II GS Unit 2 scheduled for completion in 2018;
- The overhaul and upgrade of Sir Adam Beck I GS Unit 5 in 2018-2019 and Unit 8 in 2020-2021;
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations;
- Rehabilitation of the forebay and crossover canal at the Sir Adam Beck I GS in 2020;
- Flow control equipment replacements in Northwest Operations; and
- Unit overhauls at the Sir Adam Beck Pump GS.

The total expenditures for the power canal liner rehabilitation project at the Sir Adam Beck I GS are projected at ~$125 million over 2020 and 2021. The project will repair concrete deterioration and restore the original flow capacity, ensuring reliable operations for the next 50 years.

Sustaining expenditures also include the Lower Mattagami dam safety upgrade planned for 2018 and 2019, with total expenditures of $300 million. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service.

Other planned generation development projects include the conversion of the Sir Adam Beck Units 1 and 2 to 60 Hz to increase capacity, and the expansion/redevelopment of regulated hydroelectric stations that are approaching end of life by leveraging existing infrastructure (i.e. Ranney Falls, Coniston and Calabogie generating stations). OPG will strategically assess investment in emerging generation technologies beyond the Company's core generation portfolio, including microgrid and energy storage developments, in support of Ontario's climate change strategy and to help position OPG for future growth.

Planned expenditures against previously established provision for nuclear station decommissioning and waste management are planned to increase over the planning period, from close to $300 million in 2016 to $525 million by 2021. The increase over the period reflects the following:

- The Nuclear Waste Management Organization's planned siting process activities for the Adaptive Phased Management used fuel disposal program;
- Expenditures on the Darlington refurbishment nuclear waste containers; and
- Expenditures for proceeding with OPG's proposed low and intermediate level waste deep geologic repository (L&ILW DGR), assuming receipt of a preparation and construction licence.

Eligible nuclear provision expenditures are funded from the nuclear segregated funds.

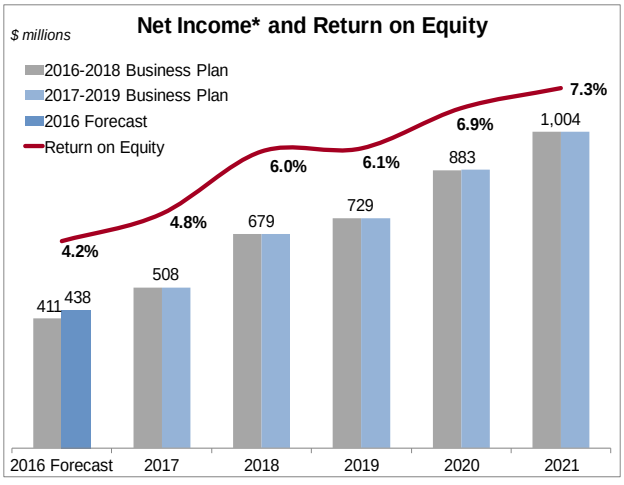
The plan also assumes provision expenditures of $85 million over the period for the decommissioning of the former Nanticoke GS, taking into account the impact on the construction and operation of the Nanticoke solar facility. OPG is in the process of preparing a definition phase plan for this work, which will form the basis for the cost estimate and schedule for the specific decommissioning activities, including demolition.

## Financial Strength

In line with the Company's commercial mandate, OPG's business plan is focused on increasing net income and return on the Shareholder's investment, through higher revenues and a continued focus on efficiency improvements, while ensuring that the Company is able to cost effectively fund its major projects and obligations. In pursuing commercial objectives, OPG takes into account the impact on Ontario electricity customers by continuing to seek further efficiencies in the Company's cost structure.

### Net Income and Return on Equity

Net income attributable to the Shareholder is forecast to increase from $438 million in 2016 to $729 million in 2019, with ROE increasing from 4.2% to 6.1%, respectively. By 2021, net income attributable to the Shareholder is projected to reach ~$1 billion, with an ROE of 7.3%. The 2017-2021 planned net income and ROE levels are unchanged from the previous plan. Although net income and ROE are forecast to improve over the planning period, different regulatory outcomes from those assumed in the plan could result in significantly lower net income and returns to the Shareholder.



* Net Income Attributable to Shareholder

The planned 2017 net income attributable to the Shareholder of $508 million is an improvement over the forecast results for 2016 of $438 million. The increase is primarily a result of:

- New regulated rates assumed to come into effect at the beginning of 2017;
- A gain on the sale of OPG's head office property expected in 2017, net of new leaseback costs and foregone lease income;
- Recognition of regulatory assets for the portion of the nuclear revenue requirement, including associated interest, deferred for future recovery under nuclear rate smoothing starting in 2017; and
- Higher capitalized interest for the Darlington refurbishment capital expenditures.
- These factors are partially offset by higher corporate level charges in 2017, planned outages at Sir Adam Beck I and DeCew II hydroelectric stations in 2017, and a gain recognized in 2016 from the OEB's decision to partially reverse a previous disallowance of Niagara Tunnel project expenditures.

Net income attributable to the Shareholder is planned to increase to $679 million in 2018 and to $729 million in 2019, primarily due to:

- Year-over-year higher capitalized interest for the Darlington refurbishment capital expenditures;
- Fewer outages at the regulated hydroelectric stations compared to 2017;
- Lower corporate level charges compared to 2017; and
- Full year of earnings from the Peter Sutherland Sr. GS starting in 2018 and earnings from the Nanticoke solar facility starting in 2019.
- These factors are partially offset by lower earnings as a result of the gain on the sale of OPG's head office property in 2017.

Net income attributable to the Shareholder is projected to continue to improve beyond 2019, reaching ~$1 billion in 2021, as the first refurbished Darlington unit returns to service and enters rate base in February 2020. This is partially offset by the depreciation of the Pickering rate base, the impact of outages at the Sir Adam Beck I GS related to the rehabilitation work on the forebay and crossover canal as well as the power canal liner, and the expiry of the current Thunder Bay biomass energy supply agreement.

Assurance of recovery of pension and OPEB costs on an accrual basis (including associated taxes) through OEB regulated rates remains a material risk to the business plan. As the generic proceeding related to the treatment of pension and OPEB costs for regulated utilities in Ontario is ongoing, the plan continues to assume that the recovery of pension and OPEB costs for 2017-2021 is limited to cash amounts and that the difference between cash and accrual amounts continues to accumulate in an OEB authorized deferral account (for both nuclear and hydroelectric operations). This is in line with the proposal put forward in OPG's May 2016 rate application. The deferral account balance is projected to accumulate to ~$480 million by the end of 2016, with further additions of ~$150 million over the 2017-2021 period. The future outcome of the OEB generic proceeding or another related OEB decision are expected to determine the recoverability of the deferral account (and associated income taxes). An OEB decision leading to a write-off of the balance would result in a substantial reduction of up to $630 million in net income over the planning period. Write-offs would be recorded in the period the applicable OEB decision is issued.

The plan reflects an updated valuation of OPG's registered pension plan filed with the Financial Services Commission of Ontario in September 2016, as approved by the Board. The valuation was performed as of January 1, 2016 and determined OPG's required cash contributions for 2016 to 2018. Compared to the previous valuation, this reduced OPG's 2016 contributions by about $100 million, while increasing the cash-to-accrual differential recorded in the deferral account for 2016.

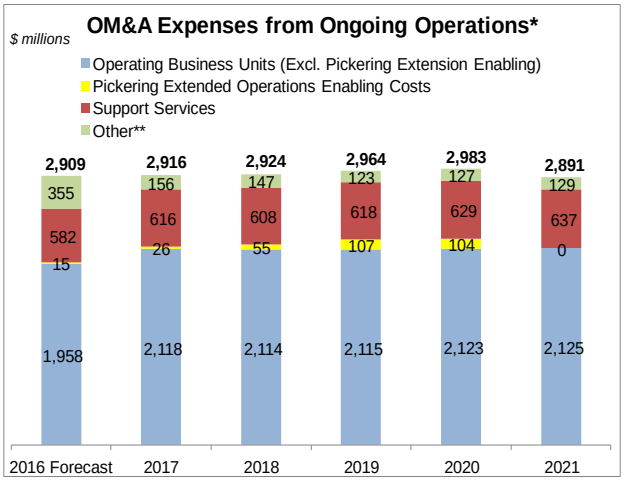
In its 2015-2017 Business Plan concurrence letter, the Shareholder recognized that OPG's existing accrual accounting methods for recovery of pension and OPEB costs are a fair representation of the long-term nature of these liabilities. OPG continues to believe that the accrual accounting basis aligned with OPG's financial accounting requirements is the most appropriate rate recovery basis for the Company's pension and OPEB costs, and has made submissions to this effect through the OEB's generic proceeding.

**Operations, Maintenance & Administration Expenses**

OM&A expenses from ongoing operations, which exclude the impact of regulatory variance and deferral account offsets as well as Darlington Refurbishment project expenses, average ~$2.9 billion per year during the 2017-2019 period, an increase of ~$25 million compared to forecast 2016 expenses. This reflects increases in business unit expenditures across the organization, partly offset by declining pension and OPEB costs. The increases in business unit expenditures are primarily driven by the following:

- Incremental outage and other work program costs to enable Pickering continued operations in line with the business case approved by the Board;

- Changes in nuclear outage scope, including maintenance work on Darlington Unit 2 to be performed during the refurbishment outage that would have otherwise occurred online or during regular outages, and Single Fuel Channel Replacement outage work at Darlington scheduled for 2017;
- Planned external hiring to fill critical staffing gaps and support effective succession planning across the Company;
- Sustaining projects to maintain asset reliability at regulated and contracted hydroelectric stations, including unit overhauls, repair work, and civil structure remediation;
- New drug testing program expected to take effect for the nuclear facilities during the planning period in accordance with CNSC Fitness for Duty regulatory requirements;




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs

- Additional maintenance and other work programs at the nuclear stations to maintain asset reliability and address equipment aging issues;
- Labour cost escalation pursuant to collective agreements, and inflationary impacts; and
- Higher nuclear liability insurance requirements pursuant to federal legislation.
- These increases are partially offset by a gradual decline in regular staffing levels after the planned increase in 2017, as well as higher expenses in 2016 associated with inventory obsolescence costs.

OM&A expenses from ongoing operations begin to decrease in 2021, reflecting the following:

- Completion of work programs to enable Pickering continued operations;
- Further reductions in staffing levels, reflecting efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life;
- Decline in nuclear outage expenses in 2021 as no major outages are planned to occur at the Darlington station in that year, partly offset by the incremental costs of the assumed station-wide Pickering VBO in 2021.

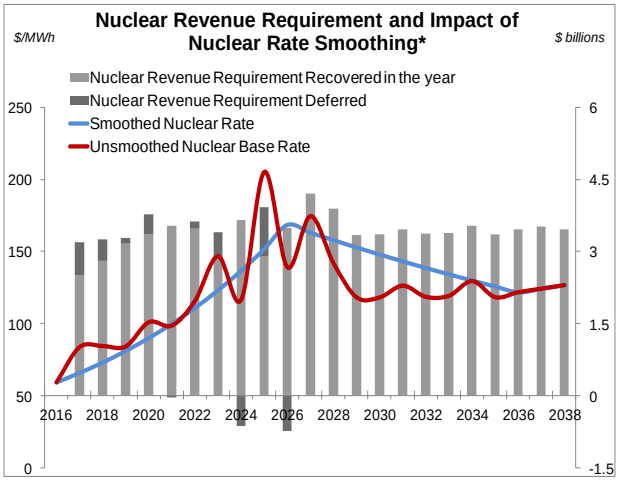
Declining pension and OPEB costs over the period are due to a combination of factors, including: projected pension asset returns, the impact of increased employee contributions, and a recently emergent, more refined US GAAP method for applying discount rates to determine the interest components of pension and OPEB costs that OPG expects to adopt for financial reporting purposes starting in 2017. This approach determines interest costs by applying individual spot rates in the yield curve to each year of cash flows, rather than a single weighted average discount rate determined based on the yield curve. This has the effect of lowering OPG's pension and OPEB costs over the planning period, compared to 2016. The factors decreasing pension and OPEB costs relative to 2016 are partly offset by the reduction in discount rates, from 4.1% for pension and 4.2% for other post retirement benefits at the beginning of 2016 to 3.6% and 3.7%, respectively. The regulated portion of the decreases in pension and OPEB costs is assumed to be offset by the pension and OPEB cash-to-accrual deferral account, resulting in a relatively small overall impact on net income.

The regulatory variance and deferral account offsets to OM&A expenses decline over the planning period. This reflects a narrowing of the differential between pension and OPEB accrual costs and cash amounts that is being recorded in the cash-to-accrual deferral account. The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

**Regulated Rates**

The plan reflects OPG's filed 2017-2021 nuclear and hydroelectric rate application, which results in an estimated average increase in a typical residential customer's monthly bill of ~0.7% or ~$1.05 each year to the end of 2021. Based on the application, the plan assumes annual hydroelectric base rate increases of ~1.5% beginning in 2017, off the existing base rates with some adjustments.

For the nuclear operations, consistent with *Ontario Regulation 53/05*, the rate application includes OPG's 11% per year rate smoothing proposal that avoids large price spikes arising during the Darlington refurbishment and at the end of Pickering operations. Under rate smoothing, the rate application seeks approval of annual nuclear revenue requirements as well as a smoothed rate trajectory for the 5-year period. The difference between the approved revenue requirements and the approved base rate trajectory will be recorded in a deferral account for recovery in the post-refurbishment period. The assumed nuclear rate trajectory from the rate application is below the 2013 LTEP assumptions for OPG's nuclear rates.



* Information beyond 2021 is included for illustrative purposes

In accordance with the regulation, the portion of the approved nuclear revenue requirement deferred for future collection will be determined by the OEB and captured in a deferral account that will earn interest at a long-term debt rate reflecting OPG's long-term borrowing cost as authorized by the OEB, compounded annually. Pursuant to the regulation, the OEB must authorize the recovery of the account balance over a period of up to 10 years beginning at the end of the refurbishment project. The rate smoothing illustration shown assumes recovery of the deferred balance over the 10-year period following the completion of the Darlington refurbishment. Based on the assumed rate trajectory, the deferral account balance, including associated interest, is projected to grow to ~$1.3 billion by 2019 and ~$1.9 billion by 2021. In accordance with US GAAP, rate smoothing deferrals in a given period will be recorded by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Accordingly, the collection of the deferred amounts in future years will not result in additional net income.

Although for planning purposes OPG assumes smoothed nuclear base rate increases of 11% per year for the full Darlington refurbishment period, the determination of the rate trajectory beyond 2021 is not part of OPG's current rate application and will be established by the OEB in the future. Leading up to that period, OPG will continue to focus on improving its cost structure and generation performance.

**Ontario Nuclear Funds Agreement Reference Plan Update**

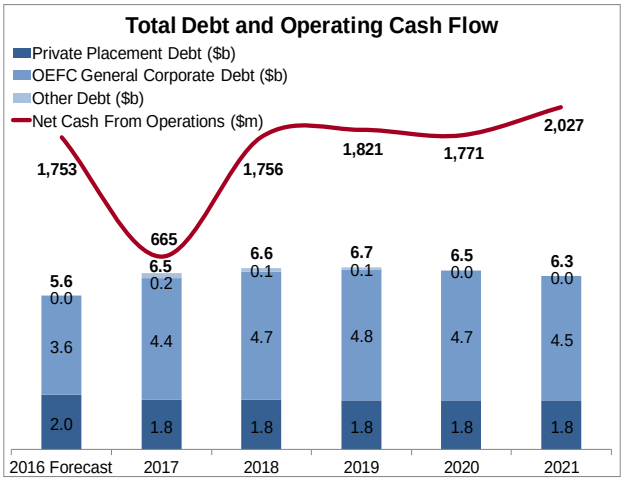
The plan reflects estimated impacts from the 2017 ONFA Reference Plan, assumed to be approved by the Minister of Finance by the end of 2016. The impacts over the planning period include the elimination of ~$180 million per year in OPG's contributions to the ONFA segregated funds, due to lower funding obligations for nuclear decommissioning and waste management. The impacts also include a decrease of ~$1.5 billion in OPG's present value accounting liability for these obligations, at the end of 2016. The main driver of the reduced obligations is lower costs associated with the long-term management of used nuclear fuel as estimated by the Nuclear Waste Management Organization. The lower costs are primarily due to a combination of a more cost effective used fuel disposal container and a delay in the assumed construction of the used fuel deep geologic repository as part of the Adaptive Phase Management plan. OPG's decommissioning and waste management obligations include those for the stations leased to Bruce Power.

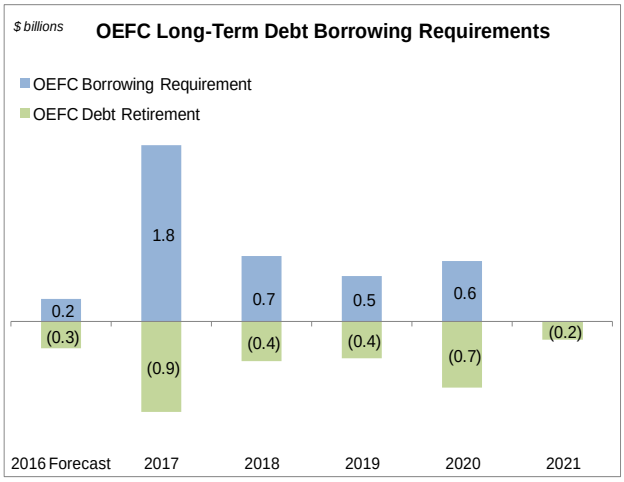
The reduction in segregated fund contributions reflects the expectation that both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund will be fully funded when the new ONFA Reference Plan with lower obligations is approved by the Province. This change improves OPG's operating cash flow but will not impact earnings, as the contributions are not treated as operating expenses. The reduction in the accounting liability lowers future depreciation, accretion and other related expenses; however, the majority of this impact does not affect net income as it will reduce amounts recovered through regulated rates. Upon approval of the new ONFA Reference Plan, OPG expects to file an update to its May 2016 rate application to reflect the lower costs to the benefit of customers.

**Financing and Liquidity**

With the exception of 2017, OPG's operating cash flow outlook is forecast to improve over the planning period, from ~$1.75 billion in 2016 to ~$2 billion in 2021. In 2017, operating cash flow is expected to

decline by over ~$1 billion from 2016 levels, primarily as nuclear production decreases by ~8 TWh, a nuclear rate rider of $10.84/MWh for collection of deferral and variance account balances expires at the end of 2016, and the collection of new regulated rates based on the anticipated timing of the OEB's decision on OPG's rate application does not begin until approximately the fourth quarter of 2017. Assuming that the OEB's decision is issued in the third quarter of 2017 and makes new rates effective January 1, 2017, the full revenue shortfall for the period between January 1, 2017 and the implementation date of the decision would be accrued in net income at the time of the decision, but would be collected over time. Higher operating cash flow starting in 2018 reflects 11% per year increases in nuclear base rates, partly offset by the impact of decreasing nuclear production in 2020 and 2021.



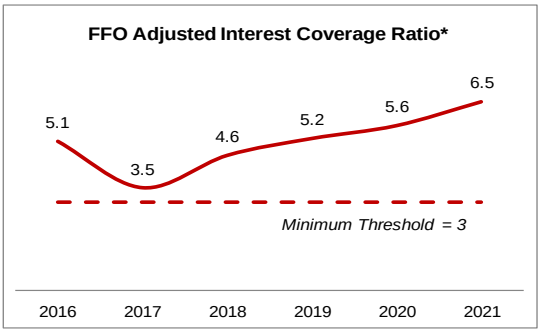




Total debt is forecast to increase from ~$5.6 billion in 2016 to ~$6.7 billion in 2019, as nuclear rate smoothing defers collection of revenue and operating cash flow does not fully fund capital expenditures. Total debt then declines to ~$6.3 billion by 2021 as operating cash flow exceeds capital expenditures. The assumed effective interest rate for new debt is 4.5%, resulting in a weighted average interest rate on OPG's long-term debt of approximately 4.75% over the planning period. The debt ratio ranges from 31% to 37% over the period, which is well below the over 50% level reflected in the OEB deemed capital structure used to set regulated rates.

The cash flow forecast for 2017 includes proceeds from the Shareholder-directed sale of OPG's head office property, an asset of OPG's unregulated business, and the payment of a corresponding dividend to the Province. No other dividends are included during the planning period at this time.

Pending ongoing discussions with the Shareholder regarding OPG's proposed strategy to migrate the capital structure to increase debt and decrease equity, with a view to pursuing a public debt offering strategy in conjunction with a focused growth strategy, the plan assumes that Darlington refurbishment expenditures and other corporate borrowing needs continue to be financed through general-purpose long-term corporate debt sourced through the Ontario Electricity Financial Corporation (OEFC).

At the end of September 2016, OPG's average term to maturity of OEFC debt is less than 6 years. OPG intends to extend this average term to reflect the longer life cycle of its assets; however the OEFC restricts the amount of debt OPG can issue with a term longer than 10 years to 50% of the amount issued at any time. This restriction increases interest rate risk and refinancing risk, as debt will need to be refinanced in the future, at which time the interest rates may be significantly higher than the current historically low rates. OPG believes that, with interest rates at these low levels, it is prudent to take advantage of beneficial market conditions to issue longer term debt to fix future interest costs.



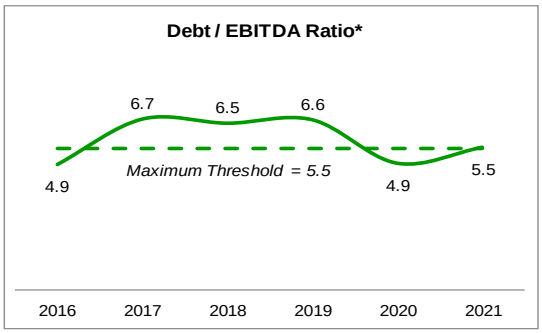

* Calculated using the methodology per OPG's external financial filings

**Credit Metrics**

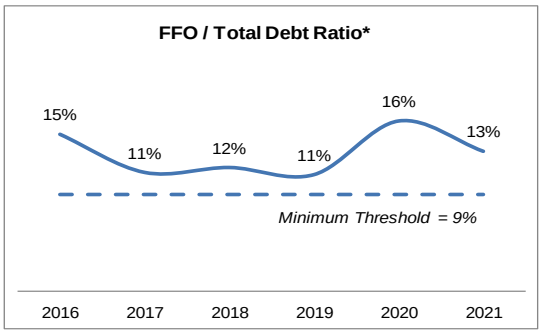
Maintaining an investment grade credit rating is critical to the Company's ability to access cost effective financing. To support this objective, OPG monitors the Funds from Operations (FFO)/Total Debt ratio and the Debt/EBITDA ratio, which are the core measures used in Standard & Poor's credit rating methodology. OPG also monitors the

FFO Adjusted Interest Coverage ratio, which is the Company's main liquidity metric.

The FFO Adjusted Interest Coverage ratio and the FFO/Total Debt ratio are forecast to remain within threshold limits during the 2017-2021 period. The Debt/EBITDA ratio exceeds the threshold limit from 2017 to 2019, as debt levels increase. Compared to 2016, the 2017-2019 ratios are also affected by a lower EBITDA, which reflects lower revenues due to the expiry of 2016 rate riders for the recovery of deferral and variance accounts, the amortization expense for which is not included in the EBITDA calculation, as well as lower hydroelectric production due to outages over the 2017-2019 period. The ratio again approaches the threshold limit in 2021, due to lower EBITDA compared to 2020.




* Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities



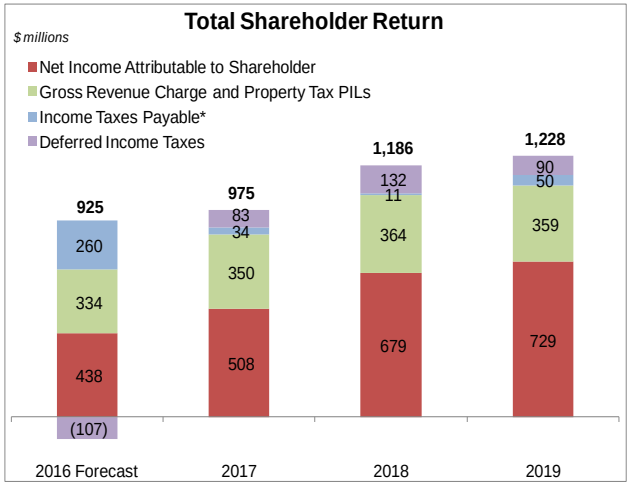

* Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities

Management believes that the forecast credit metrics and operating cash flow, combined with the support for future collection of rate smoothing deferrals under the regulation, should continue to support OPG's current investment grade credit rating. Different regulatory outcomes from those assumed in the plan could result in significantly lower cash flows, increased borrowing and weaker credit metrics, increasing the risk of a credit rating downgrade. In turn, this could increase costs, limit borrowing capacity, and/or necessitate curtailment of project or other expenditures.

### Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric GRC payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute ~$3.4 billion in Total Shareholder Return over the 2017-2019 period.

The 2017 Total Shareholder Return on OPG's fiscal basis is projected at $975 million, an increase over $925 million forecast for 2016. Total Shareholder Return is projected to increase to ~$1.2 billion per year in 2018 and 2019, as net income increases.




* Includes income tax PILs and amounts recoverable from, or payable to ratepayers

## Social Licence

OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous Relations.

### Environment and Climate Change

OPG's virtually carbon free generation has underpinned the decarbonisation of the power sector and can act as a catalyst for reducing carbon emissions from the broader economy. With a generating fleet that is 99% emission free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. OPG's business plan supports Ontario's climate change strategy and technology deployment and electrification objectives, including microgrids, energy storage technology and electric vehicles. In addition to continuing to drive a focus on environmental performance through business plan targets, the decisions to proceed with the Darlington refurbishment and to pursue continued operations at Pickering will contribute to achieving Ontario's climate change objectives by leveraging OPG's lower-priced, carbon-free baseload nuclear power. It is expected that the refurbished Darlington station will

reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million cars per year from Ontario's roads.

Climate change adaption and related safety considerations are a key aspect of OPG's plans for the hydroelectric facilities. These plans consider the impact of water availability, its utilization and the associated environmental and stewardship responsibilities. OPG is also taking steps to better understand the potential changes in water flow conditions that these facilities may experience, including consideration of extreme weather events. This includes development of flood forecasting models in an effort to better predict potential impacts of these changes and to put in place appropriate risk mitigation plans. OPG will continue to operate its hydroelectric facilities by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds while optimizing electricity production.

OPG is in the process of obtaining approvals, establishing processes, and implementing systems for compliance with the requirements of Ontario's new climate change legislation including a cap-and-trade program effective January 1, 2017. Overall, compliance with these requirements is not expected to have a significant financial cost impact on the plan given OPG's virtually emission free generating fleet.

**Public Safety**

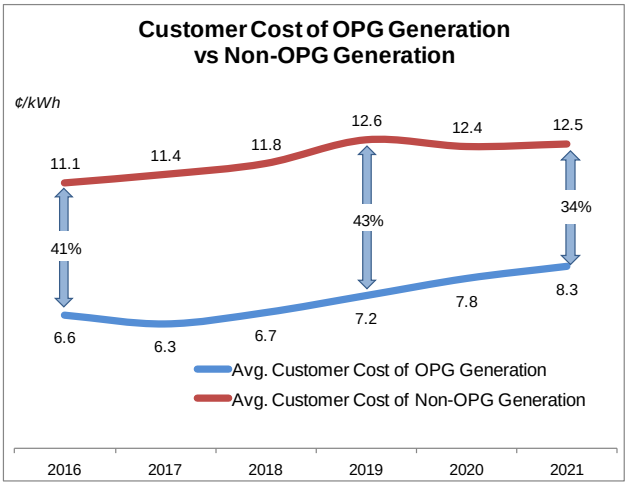
OPG is committed to high standards of workplace and public safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. In particular, OPG will continue to operate with nuclear safety as an overriding priority, by maintaining a strong focus on nuclear safety programs and continuing to invest in nuclear safety systems. In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. OPG also will continue to demonstrate strong industry leadership with its hydroelectric Dam Safety Program, which encompasses public safety and emergency management over the Company's 238 dams and 65 hydroelectric facilities. Many aspects of the program are considered to be international best practice.

**Indigenous Relations**

Throughout the planning period, OPG will remain committed to engaging proactively and building long-term, mutually beneficial working relationships with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing generation-related development partnerships, such as the Peter Sutherland Sr. GS and the Nanticoke solar facility, collaborating on capacity building initiatives and projects, such as the recently completed shoreline restoration projects, and conducting community outreach efforts.

**Moderating Electricity Prices and Contributing to the Economy**

Taking into account the assumed rate increases over the 2017-2021 period from OPG's current rate application, the cost to customers of electricity generated by OPG is expected to remain over ~40% below the average non-OPG cost of electricity in Ontario to 2019 and close to ~35% lower by 2021. The expected average increase from OPG's nuclear and hydroelectric rate application on a typical residential customer's monthly bill over the period to 2021 is estimated to be ~0.7% each year.




OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station. According to The Conference Board of Canada, Ontario's Gross Domestic Product is estimated to increase by a total of ~$90 billion in the period spanning to the end of the post-refurbishment life of the station.

## RECOMMENDATION / RESOLUTION

It is recommended that the Board of Directors approve OPG's 2017-2019 Business Plan including the financial projection for the 2020-2021 period.

**Recommended by:**

[original signed by]
Ken Hartwick
Senior Vice President,
Finance, Strategy, Risk and
Chief Financial Officer

**Approved for submission to the Board of Directors by:**

[original signed by]
Jeff Lyash
President and CEO

This Board memo was reviewed and approved for submission to the Board of Directors by the Audit and Risk Committee at their meeting on November 8, 2016.

## APPENDICES

1. Key Planning Assumptions
2. Key Risks
3. Financial and Headcount Plan Information
4. Nuclear Financial Plan, Operational Targets, and Initiatives
5. Nuclear Strategic Framework
6. Renewable Generation & Power Marketing Financial Plan, Operational Targets, and Initiatives
7. Business and Administrative Services (BAS) Financial Plan, Operational Targets, and Initiatives

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

- Darlington Unit 2 is refurbished from October 2016 to February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in July 2021.
- All six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
- A station-wide Vacuum Building Outage takes place at Pickering in 2021
- The plan reflects currently approved accounting station service lives for Pickering to December 2020, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061. The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.
- The first Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- The site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental expenses are allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities starting in 2018
- The following major projects are carried out at the Sir Adam Beck plants:
    - Sir Adam Beck Pump GS reservoir rehabilitation is completed in the first half of 2017
    - Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz over the 2018-2020 period
    - Sir Adam Beck I GS power canal liner rehabilitation takes place over 2020 and 2021
- Peter Sutherland Sr. GS is in service in 2017 and Lower Mattagami dam safety upgrade in 2019
- The Thunder Bay GS operates until the end of the current biomass energy supply agreement in 2020
- The Nanticoke solar facility is in service in 2019. The former Nanticoke GS is decommissioned, taking into account the impact on the construction and operation of the solar facility.
- Nuclear base rates increase by 11% per year under nuclear rate smoothing, effective January 1, 2017. Effective January 1, 2017, hydroelectric base rates increase by ~1.5% per year, off the existing base rates with some adjustments, under an incentive regulation approach.
- Recoveries for pension and OPEB are limited to cash requirements in the 2017-2021 rate application, pending the outcome of OEB's generic consultation and any other applicable OEB determinations, with the difference between cash and accrual amounts continuing to accumulate in the existing deferral account (for nuclear and hydroelectric operations)
- Carbon pricing in Ontario is based on the Province's cap-and-trade program effective January 1, 2017
- The sale of OPG's head office property, an asset of the unregulated business, is closed in the second quarter of 2017 and a corresponding dividend paid in 2017, as directed by the Shareholder. No other dividends are assumed in the plan at this time.
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. An accounting discount rate of 3.6% is used for valuing pension costs and 3.7% for other post retirement benefit costs.
- The plan reflects the January 1, 2016 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and a subsequent valuation as of January 1, 2019
- Due to inherent uncertainties, inflationary impacts on salary costs are assumed for periods after the expiry of the current collective agreements
- The 2017 ONFA Reference Plan is assumed to be approved by the Province by the end of 2016
- Existing OEFC debt platform continues to be used for long-term corporate debt purposes, pending ongoing discussions with the Province regarding OPG's proposal to move to a public debt platform. The assumed effective interest rate for new debt is 4.5%.
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP for the full planning period

## APPENDIX 2: KEY RISKS

The key risks associated with the 2017-2019 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule;
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance;
- Risk of the Province not concurring with the refurbishment of the subsequent Darlington units;
- Inability to retain and attract effective, knowledgeable and engaged leadership talent during the Darlington refurbishment and continued Pickering operations given an aging workforce and Management group compensation constraints;
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges;
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance;
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures; and
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions.

### Rate Regulation Risks

OEB rulings impacting OPG's rate regulated operations may be unfavourable compared to assumptions in the plan, including the following:

- Inability to receive sufficient assurance from the OEB for future recovery of the pension and OPEB cash-to-accrual deferral account balance projected at ~$480 million by the end of 2016 with further additions totalling ~$150 million over the 2017-2021 period, and associated taxes, which would result in a write-off against net income;
- An OEB-set nuclear rate smoothing trajectory that does not provide sufficient cash flow to fund operations, projects and/or obligations, and/or to maintain the current investment grade credit rating. A credit rating downgrade would increase borrowing costs and could reduce borrowing capacity;
- OEB-approved revenue requirements that do not allow for recovery of the full costs of the regulated operations and/or do not allow the regulated business to earn an appropriate return; and
- An effective date for new regulated rates that is later than the assumed January 1, 2017 date, which would reduce 2017 planned net income by ~$50 to $60 million per month.

### Financial Risks

- Risk of delay in the Province's approval of the 2017 ONFA Reference Plan to 2017, which could result in a reduction in 2017 planned nuclear segregated fund earnings, through a reduction limiting fund asset balance sheet values to the updated, lower ONFA funding obligations. The impact of this reduction is currently reflected in the 2016 forecast net income on the assumption that the new reference plan is approved by the end of 2016.
- Risk of lower than planned returns on segregated nuclear and pension fund assets as a result of various market factors, including equity prices, interest rates, inflation, and commodity prices, which would lower net income and potentially increase future funding requirements compared to the plan;
- Risk of lower discount rates and other differences in assumptions for future pension and OPEB accounting and funding valuations, compared to the plan, including those due to underlying financial market conditions; and
- Risk of adoption of IFRS for financial reporting purposes, either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements under US GAAP or the Shareholder's requirement to consolidate OPG's results using IFRS. Adoption of IFRS is expected to cause significant net income volatility compared to US GAAP.

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to the Shareholder | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Net Income | 455 | 525 | 695 | 745 | 899 | 1,020 |
| Earnings Before Tax | 608 | 641 | 838 | 885 | 1,216 | 1,262 |
| Return on Equity* *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Nuclear Total Generating Cost per MWh** *($/MWh)* | 63.2 | 75.6 | 74.6 | 74.5 | 77.1 | 77.3 |
| Hydroelectric Total Generating Cost per MWh** *($/MWh)* | 25.1 | 26.4 | 30.1 | 30.3 | 30.0 | 29.0 |
| Enterprise Total Generating Cost per MWh** *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| FFO / Total Debt Ratio *(%) (Minimum threshold of 9%)* | 15% | 11% | 12% | 11% | 16% | 13% |
| Debt / EBITDA Ratio (times) *(Maximum threshold of 5.5)* | 4.9 | 6.7 | 6.5 | 6.6 | 4.9 | 5.5 |
| FFO Adjusted Interest Coverage Ratio* (times) *(Minimum threshold of 3)* | 5.1 | 3.5 | 4.6 | 5.2 | 5.6 | 6.5 |
| Debt Ratio *(%)* | 34% | 37% | 36% | 35% | 33% | 31% |
| Net Cash from Operations | 1,753 | 665 | 1,756 | 1,821 | 1,771 | 2,027 |
| Cash Balance at Year-End | 275 | 259 | 264 | 246 | 224 | 462 |
| Total Debt at Year-End | 5,608 | 6,458 | 6,630 | 6,662 | 6,549 | 6,336 |
| Total Return to Shareholder*** | 925 | 975 | 1,186 | 1,228 | 1,549 | 1,590 |
| OM&A Expenses from Ongoing Operations | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Darlington Refurbishment Capital Expenditures | 1,037 | 1,152 | 1,113 | 1,111 | 1,045 | 1,061 |
| Darlington Refurbishment In-Service Additions | 387 | 398 | 2 | - | 4,849 | - |
| Capital Expenditures excluding Darlington Refurbishment | 702 | 626 | 792 | 743 | 617 | 498 |
| In-Service Additions excluding Darlington Refurbishment | 587 | 1,003 | 593 | 1,031 | 558 | 594 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 302 | 425 | 432 | 438 | 494 | 527 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Nuclear TGC/MWh adjusted for lower production due to the Darlington refurbishment outages is: $63.8/MWh in 2017, $63.2/MWh in 2018, $65.8/MWh in 2019, $62.8/MWh in 2020 and $60.4/MWh in 2021.

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

| Total Shareholder Return | Provincial Fiscal Year Basis ending March 31 | | | |
|---|---|---|---|---|
| *$ millions* | 2017 | 2018 | 2019 | 2020 |
| **Net Income Attributable to Shareholder** | **349** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | |
| GRC: Payable to OEFC & Niagara Parks Commission | 321 | 332 | 344 | 343 |
| Property Tax Payable to OEFC | 15 | 18 | 19 | 19 |
| **Total Non Income Tax PILs** | **336** | **350** | **363** | **362** |
| **Income Tax PILs** | **96** | **166** | **135** | **170** |
| **Total Shareholder Return** | **781** | **1,218** | **1,176** | **1,258** |

| Operating Statement - Years Ended December 31 | Forecast | Business Plan | | |
|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 |
| Electricity Generation Revenues | 5,282 | 4,641 | 5,165 | 5,333 |
| Fuel and Gross Revenue Charge | 727 | 675 | 685 | 689 |
| **Generation Sales Gross Margin** | **4,555** | **3,966** | **4,480** | **4,644** |
| Net Trading Margin | 22 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 338 | 298 | 290 | 280 |
| **Total Gross Margin** | 4,916 | 4,282 | 4,788 | 4,943 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,761 | 2,840 | 2,864 | 2,947 |
| Accretion on Nuclear Waste and Other Liabilities | 926 | 969 | 983 | 1,013 |
| Earnings on Nuclear Funds | (755) | (818) | (852) | (886) |
| Depreciation and Amortization | 1,268 | 832 | 876 | 962 |
| Property Taxes | 48 | 47 | 47 | 48 |
| Restructuring | - | 3 | - | - |
| **Total Expenses** | 4,248 | 3,872 | 3,918 | 4,084 |
| **Income before Interest and Other Income** | **668** | **410** | **870** | **858** |
| Net Interest Expense | 125 | 120 | 71 | 14 |
| Other (Income)/Expense* | (65) | (351) | (39) | (40) |
| **Income before Tax** | **608** | **641** | **838** | **885** |
| Income Tax | 153 | 116 | 143 | 140 |
| **Net Income** | **455** | **525** | **695** | **745** |
| **Net Income Attributable to the Shareholder** | **438** | **508** | **679** | **729** |
| Net Income Attributable to Non-Controlling Interests | 16 | 17 | 16 | 16 |

* Includes $28M and $9M in 2016, $28M and $10M in 2017, $26M and $11M in 2018, $27M and $12M in 2019 representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, also includes a pre-tax gain of $296M on the Shareholder-directed sale of OPG's head office property, as well as a pre-tax gain of $15M on the sale of the R.L Hearn GS site, both assets of OPG's unregulated business.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 |
|---|---|---|---|---|
| ***Assets*** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | 275 | 259 | 264 | 246 |
| Available-for-sale securities | 233 | 217 | 196 | 177 |
| Short-term investments | 70 | - | - | - |
| Accounts receivable* | 551 | 759 | 562 | 602 |
| Fuel inventory | 308 | 296 | 295 | 231 |
| Materials and supplies | 96 | 96 | 96 | 96 |
| Other current assets | 207 | 116 | 116 | 116 |
| | 1,740 | 1,743 | 1,529 | 1,468 |
| **Property, plant and equipment and intangible assets** | | | | |
| Fixed and intangible assets (net)** | 20,200 | 21,273 | 22,365 | 23,450 |
| **Other assets** | | | | |
| Nuclear fixed asset removal and nuclear waste management funds | 15,950 | 16,613 | 17,309 | 17,981 |
| Long-term materials and supplies | 340 | 339 | 332 | 322 |
| Regulatory assets (net) | 6,412 | 7,075 | 7,532 | 7,637 |
| Investments subject to significant influence | 321 | 308 | 299 | 288 |
| Other long-term assets | 63 | 63 | 63 | 63 |
| | 23,086 | 24,398 | 25,534 | 26,292 |
| ***Total Assets*** | **45,026** | **47,414** | **49,428** | **51,211** |
| ***Liabilities*** | | | | |
| **Current liabilities** | | | | |
| Short-term notes payable | 2 | 205 | 125 | 75 |
| Accounts payable and accrued charges | 1,153 | 1,585 | 1,731 | 1,870 |
| Deferred revenue due within one year | 12 | 12 | - | - |
| Current income taxes payable | 121 | 49 | 91 | 128 |
| Long-term debt due within one year | 1,103 | 398 | 368 | 663 |
| | 2,391 | 2,249 | 2,316 | 2,736 |
| **Long-term debt** | 4,503 | 5,855 | 6,137 | 5,924 |
| **Other liabilities** | | | | |
| Fixed asset removal and nuclear waste management liabilities** | 19,496 | 20,177 | 20,863 | 21,592 |
| Pension liabilities (non-current) | 3,933 | 3,930 | 3,936 | 3,879 |
| Other post-employment benefit liabilities (non-current) | 3,035 | 3,128 | 3,223 | 3,319 |
| Long-term accounts payable and accrued charges | 185 | 168 | 173 | 174 |
| Deferred revenue | 298 | 351 | 419 | 409 |
| Deferred income taxes | 751 | 834 | 966 | 1,054 |
| | 27,698 | 28,590 | 29,579 | 30,428 |
| ***Equity*** | | | | |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 5,536 | 5,822 | 6,501 | 7,230 |
| Accumulated other comprehensive loss | (366) | (365) | (367) | (369) |
| Equity attributable to non-controlling interests | 137 | 138 | 136 | 135 |
| | 10,434 | 10,721 | 11,397 | 12,123 |
| ***Total Liabilities and Equity*** | **45,026** | **47,414** | **49,428** | **51,211** |

* As at December 31, 2017, includes accrued revenues for new regulated rates for the period from January 1, 2017 to the implementation date of the OEB's decision, which is assumed to be received in the third quarter of 2017. The accrued balance is assumed to be fully collected by the end of 2018.

** As at December 31, 2016, reflects an adjustment that reduces the nuclear decommissioning and waste management liabilities based on cost estimates from the 2017 ONFA Reference Plan update process.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 | Projection<br>2020 | <br>2021 |
|---|---|---|---|---|---|---|
| Nuclear Operations* | 1,601 | 1,725 | 1,735 | 1,786 | 1,777 | 1,689 |
| Renewable Generation & Power Marketing | 370 | 417 | 432 | 433 | 448 | 433 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **1,973** | **2,144** | **2,169** | **2,222** | **2,228** | **2,125** |
| Business and Administrative Services<br>(Chief Information Officer, Real Estate, Supply Chain) | 298 | 299 | 295 | 300 | 305 | 309 |
| Finance (excl. Insurance)<br>(Finance, Risk & Assurance, Corp. Bus. Development) | 82 | 84 | 81 | 80 | 80 | 81 |
| Insurance | 31 | 42 | 45 | 48 | 52 | 53 |
| People/Culture & Communications | 135 | 149 | 148 | 150 | 152 | 151 |
| Legal/Ethics & Compliance<br>(Law, Regulatory Affairs, Environment) | 32 | 36 | 32 | 32 | 33 | 35 |
| Corporate Office | 5 | 7 | 7 | 8 | 8 | 8 |
| **Total Support Services** | **582** | **616** | **608** | **618** | **629** | **637** |
| **Total Business Unit Expenditures** | **2,555** | **2,760** | **2,776** | **2,840** | **2,856** | **2,762** |
| Centrally Held Pension and OPEB | 277 | 89 | 60 | 42 | 37 | 37 |
| Other (incl. Cost of Goods Sold) | 77 | 67 | 88 | 81 | 90 | 92 |
| **Total Ongoing Operations** | **2,909** | **2,916** | **2,924** | **2,964** | **2,983** | **2,891** |
| OEB Variance and Deferral Account Offsets | (129) | (103) | (62) | (12) | (7) | (6) |
| Darlington Refurbishment Project | 3 | 49 | 16 | 7 | 52 | 26 |
| Nuclear New Build | 1 | 2 | 7 | 10 | 11 | 11 |
| **Total OM&A Expenses** | **2,785** | **2,863** | **2,886** | **2,968** | **3,040** | **2,922** |

* Total Pickering extended operations enabling costs are: $15M in 2016, $26M in 2017, $55M in 2018, $107M in 2019 and $104M in 2020.

| Regular Headcount by Business Unit | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Nuclear Operations | 5,552 | 5,760 | 5,755 | 5,678 | 5,571 | 5,496 |
| Renewable Generation & Power Marketing | 1,524 | 1,540 | 1,517 | 1,508 | 1,484 | 1,445 |
| Other Unregulated Operations | 2 | 5 | 5 | 5 | 5 | 5 |
| **Total Operations** | **7,078** | **7,305** | **7,277** | **7,191** | **7,060** | **6,946** |
| Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain) | 829 | 864 | 863 | 862 | 849 | 849 |
| Finance (Finance, Risk & Assurance, Corp. Bus. Development) | 350 | 351 | 343 | 337 | 332 | 332 |
| People/Culture & Communications | 647 | 681 | 674 | 678 | 673 | 665 |
| Legal/Ethics & Compliance (Law, Regulatory Affairs, Environment) | 96 | 99 | 98 | 98 | 98 | 98 |
| Corporate Office | 9 | 12 | 12 | 12 | 12 | 12 |
| **Total Support Services** | **1,931** | **2,007** | **1,990** | **1,987** | **1,964** | **1,956** |
| **Total Ongoing Operations** | **9,009** | **9,312** | **9,267** | **9,178** | **9,024** | **8,902** |
| Darlington Refurbishment Project | 458 | 631 | 642 | 626 | 610 | 642 |
| **Total Regular Headcount** | **9,467** | **9,943** | **9,909** | **9,804** | **9,634** | **9,544** |

| Capital Expenditures<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 | Projection<br>2020 | <br>2021 |
|---|---|---|---|---|---|---|
| **Sustaining** | | | | | | |
| **Nuclear** | 291 | 322 | 319 | 299 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | | |
| Sir Adam Beck 1 Canal Liner Rehabilitation | - | - | 1 | 1 | 62 | 62 |
| Sir Adam Beck Pump GS Reservoir Rehabilitation | 40 | 7 | - | - | - | - |
| Other Projects | 109 | 125 | 111 | 120 | 153 | 133 |
| **Total Regulated Hydroelectric** | 149 | 132 | 112 | 122 | 215 | 195 |
| **Contracted Generation Portfolio** | | | | | | |
| Lower Mattagami Dam Safety Upgrade (formerly Adam Creek Spillway Expansion) | - | 5 | 145 | 145 | 5 | - |
| Other Projects | 39 | 32 | 32 | 24 | 11 | 6 |
| **Total Contracted Generation Portfolio** | 39 | 37 | 177 | 169 | 16 | 6 |
| **Support Services** | 59 | 49 | 38 | 38 | 35 | 35 |
| **Total Sustaining Capital** | **537** | **540** | **646** | **628** | **555** | **480** |
| **Generation Development Projects*** | | | | | | |
| **Hydroelectric Development** | | | | | | |
| Peter Sutherland Sr. GS** | 145 | 41 | 5 | 0 | - | - |
| Sir Adam Beck Units 1 & 2 Conversion | - | 2 | 17 | 43 | 27 | - |
| Lower Mattagami River Project** | 16 | - | - | - | - | - |
| Ranney Falls GS Expansion | 2 | 35 | 18 | 8 | - | - |
| Coniston GS Redevelopment | - | - | 6 | 28 | 14 | 7 |
| Calabogie GS Redevelopment | - | 3 | 4 | 34 | 20 | 11 |
| Other | 1 | 0 | 1 | 2 | 2 | - |
| **Total Hydroelectric Development** | 164 | 81 | 51 | 115 | 63 | 18 |
| **Darlington Refurbishment Project***** | 1,037 | 1,152 | 1,113 | 1,111 | 1,045 | 1,061 |
| **Nanticoke Solar Project** | 1 | 5 | 95 | - | - | - |
| **Total Generation Development Capital** | **1,202** | **1,239** | **1,259** | **1,226** | **1,107** | **1,079** |
| **Total Capital Expenditures** | **1,739** | **1,778** | **1,905** | **1,854** | **1,662** | **1,559** |

* While in definition phase, projects are budgeted by Corporate Business Development and, while in execution phase, projects are budgeted by RG&PM

** Includes expenditures budgeted by RG&PM and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| **Provision Expenditures** *(in millions of dollars)* | Forecast 2016 | Business Plan 2017 | 2018 | 2019 | Projection 2020 | 2021 |
|---|---|---|---|---|---|---|
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | | |
| Nuclear Operations* | 272 | 358 | 377 | 418 | 471 | 511 |
| Support Services | 15 | 16 | 16 | 13 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **287** | **375** | **392** | **431** | **485** | **525** |
| Nanticoke GS Decommissioning | | 46 | 32 | 6 | 1 | 1 |
| Other | 16 | 4 | 8 | 1 | 9 | 1 |
| **Total Thermal Decommissioning Expenditures** | **16** | **50** | **40** | **7** | **10** | **2** |
| **Total Provision Expenditures** | **302** | **425** | **432** | **438** | **494** | **527** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| **Financing and Liquidity Outlook - Years Ended Dec 31** *(in millions of dollars)* | | Forecast 2016 | Business Plan 2017 | 2018 | 2019 | Projection 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| ***Opening Cash Balance*** | | **464** | **275** | **259** | **264** | **246** | **224** |
| **Net Operating Cash Inflows before the following:** | | **2,739** | **1,531** | **2,648** | **2,756** | **2,715** | **2,953** |
| Interest Paid | | (266) | (286) | (288) | (295) | (298) | (289) |
| Nuclear Funds Contribution | | (150) | - | - | - | - | - |
| Pension Fund Contribution | | (253) | (248) | (251) | (299) | (305) | (308) |
| OPEB Payments | | (120) | (113) | (118) | (123) | (128) | (133) |
| Internally Funded Nuclear Provision Expenditures | | (196) | (220) | (236) | (217) | (213) | (195) |
| **Net Cash from Operations** | | **1,753** | **665** | **1,756** | **1,821** | **1,771** | **2,027** |
| **Investing Activities** | | | | | | | |
| Sustaining Capital Expenditures | | (537) | (540) | (646) | (628) | (555) | (480) |
| Darlington Refurbishment | | (1,037) | (1,152) | (1,113) | (1,111) | (1,045) | (1,061) |
| Peter Sutherland Sr. GS (PS) | | (145) | (41) | (5) | (0) | - | - |
| Nanticoke Solar | | (1) | (5) | (95) | - | - | - |
| Other Generation Development | | (19) | (40) | (46) | (115) | (63) | (18) |
| **Cash Outflow for Capital Investments** | | **(1,739)** | **(1,778)** | **(1,905)** | **(1,854)** | **(1,662)** | **(1,559)** |
| (Investment in) Proceeds from Deposit Note (PS) | | 110 | 70 | - | - | - | - |
| Pre-tax Proceeds from Sale of OPG Head Office | | - | 400 | - | - | - | - |
| Pre-tax Proceeds from Sale of R.L. Hearn GS Site | | | 16 | | | | |
| Investment in Hydro One Shares | | (213) | - | - | - | - | - |
| Other | | (4) | - | - | - | - | - |
| **Net Cash Outflow for Investing Activities** | | **(1,846)** | **(1,292)** | **(1,905)** | **(1,854)** | **(1,662)** | **(1,559)** |
| **Financing Activities** | | | | | | | |
| General Corporate (OEFC) | - *Debt Issuance/Refinancing* | 220 | 1,750 | 650 | 450 | 600 | - |
| | - *Debt Retirement* | (270) | (900) | (395) | (365) | (660) | (185) |
| Project Financing (Private Placement) | - *Debt Issuance/Refinancing* | 200 | - | - | - | - | 225 |
| | - *Debt Retirement* | (3) | (203) | (3) | (3) | (3) | (228) |
| Short-Term Notes | - *Net Issuance (Repayment)* | (223) | 203 | (80) | (50) | (50) | (25) |
| Dividends Paid | | - | (223) | - | - | - | - |
| Distribution Paid to Non-Controlling Interests | | (19) | (16) | (17) | (17) | (18) | (18) |
| **Net Cash from Financing Activities** | | **(95)** | **612** | **155** | **15** | **(131)** | **(231)** |
| **Net Cash (Outflow) Inflow for Period** | | **(189)** | **(16)** | **5** | **(18)** | **(22)** | **238** |
| ***Ending Cash Balance*** | | ***275*** | ***259*** | ***264*** | ***246*** | ***224*** | ***462*** |
| ***Total Debt at Year-End*** | | ***5,608*** | ***6,458*** | ***6,630*** | ***6,662*** | ***6,549*** | ***6,336*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | | |
| Base* | 1,172 | 1,196 | 1,215 | 1,254 | 1,263 | 1,281 |
| Outage Incremental | 319 | 392 | 373 | 343 | 328 | 322 |
| Project Portfolio | 94 | 111 | 91 | 82 | 82 | 87 |
| Pickering Continued Operations Enabling Costs | 15 | 26 | 55 | 107 | 104 | - |
| Darlington Refurbishment Project | 3 | 49 | 16 | 7 | 52 | 26 |
| Nuclear New Build | 1 | 2 | 7 | 10 | 11 | 11 |
| **Total Nuclear OM&A** | **1,605** | **1,776** | **1,758** | **1,803** | **1,841** | **1,727** |
| **Capital** | | | | | | |
| Project Portfolio (including Spares and Minor Fixed Assets)** | 291 | 322 | 319 | 299 | 289 | 244 |
| Darlington Refurbishment Project (excl. Support Services) | 1,008 | 1,119 | 1,084 | 1,082 | 1,019 | 1,035 |
| **Total Nuclear Capital** | **1,299** | **1,441** | **1,403** | **1,381** | **1,308** | **1,279** |
| **Provision Expenditures** | | | | | | |
| ONFA Funded | 85 | 150 | 147 | 206 | 264 | 325 |
| Internally Funded - Base | 101 | 115 | 115 | 122 | 125 | 127 |
| Internally Funded - Projects | 54 | 49 | 70 | 45 | 45 | 40 |
| Internally Funded - Darlington Refurbishment Waste Containers | 31 | 44 | 45 | 45 | 38 | 19 |
| **Total Nuclear Provision Expenditures** | **272** | **358** | **377** | **418** | **471** | **511** |
| **Fuel Expense** (Pickering and Darlington) | **263** | **223** | **220** | **228** | **217** | **198** |

* Includes an estimated $4M to $5M per year for work in support of the RG&PM business unit

** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2017-2019 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station and continuing work on fuel channel inspections at the Pickering station.

| | | | Pickering | | | | | Darlington[1] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | 2016 Target | 2016 Forecast | 2017 Target | 2018 Target | 2019 Target | 2016 Target | 2016 Forecast | 2017 Target | 2018 Target | 2019 Target |
| All Injury Rate[2] (#/200k hrs worked) | N/A | 0.69 | 0.24 | 0.49 | 0.24 | 0.24 | 0.24 | 0.24 | 0.23 | 0.24 | 0.24 | 0.24 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 38.17 | 111.50 | 104.50 | 126.90 | 137.30 | 153.30 | 65.00 | 80.90 | 111.90 | 82.70 | 78.40 |
| Unit Capability Factor (%) | 92.0 | 91.3 | 77.6 | 75.3 | 71.5 | 72.0 | 72.6 | 91.1 | 90.0 | 85.1 | 86.0 | 87.8 |
| Forced Loss Rate (%) | 1.00 | 0.38 | 5.00 | 4.37 | 5.00 | 5.00 | 5.00 | 1.00 | 1.93 | 1.00 | 1.00 | 1.00 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 7 | 55 | 80 | 28 | 28 | 28 | 20 | 20 | 15 | 10 | 7 |
| WANO NPI (Index) | N/A | 93.5 | 72.3 | 75.6 | 69.7 | 67.2 | 65.9 | 87.3 | 85.5 | 83.1 | 90.7 | 91.0 |
| Human Performance Error Rate | N/A | 0.0010 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0053 | 0.0020 | 0.0020 | 0.0020 |
| Total Generating Cost per MWh[3] | N/A | $38.93 | $71.09 | $72.46 | $78.83 | $80.09 | $81.49 | $47.35 | $46.46 | $49.75 | $49.54 | $52.33 |

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Also applies to Darlington Refurbishment Project and Contractors.

[3] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment.

## Initiatives

The following initiatives represent the focus areas of the Nuclear business unit aimed at closing performance gaps in order to achieve targeted results:

- **Outage Execution:** This initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage day targets. Areas for improvement include: outage schedule and resource planning quality; implementation of a long-term purchased services agreement to optimize contracted work and improve quality of supplemental staff execution; inspection and maintenance execution improvements; Life Cycle Management Plan development improvements; and studying the option of moving Pickering to a 30-month outage cycle.
- **Workforce Planning & Resourcing Initiative:** This initiative focuses on implementing the resourcing strategy to support the safe operation of the plants and successful completion of the Darlington refurbishment, while minimizing disruption and costs associated with the Pickering end of commercial operations. A dedicated team provides oversight on the resourcing strategies and resourcing approval process.
- **Equipment Reliability:** This initiative aims to improve equipment reliability, improve effectiveness of the maintenance program and reduce equipment failures to meet forced loss rate targets.
- **Project Excellence Initiative:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Parts Improvement Sustainment:** This initiative aims to sustain and continuously improve on the results of the 19 completed sub-initiatives of the overall Parts Improvement Project. The focus of the Parts Improvement Project has been on obtaining the right parts on time, reducing churn in the work management system, and ultimately improving equipment reliability through the completion of the 19 cross-functional sub-initiatives across the Engineering, Supply Chain, Fleet Operations & Maintenance, and Work Management functions.
- **Human Performance:** This initiative focuses on: 1) Behaviours associated with procedural use and adherence; 2) Leadership accountability whereby leaders understand and model the behaviours expected from all staff; and 3) Supervisor effectiveness whereby supervisors set and communicate clear expectations to positively influence behaviours.

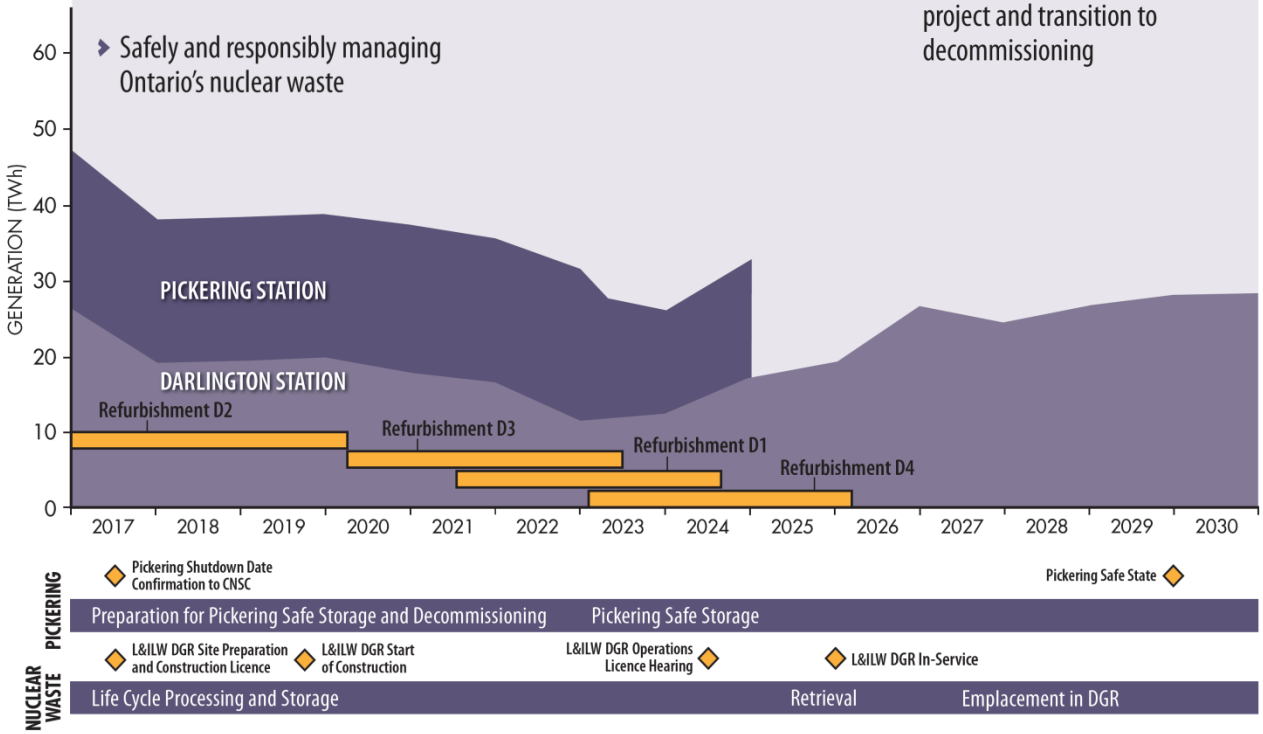
## APPENDIX 5: NUCLEAR STRATEGIC FRAMEWORK

# Nuclear Strategic Framework

## Nuclear Cornerstones of Excellence

• Safety • Reliability • Value for Money • Human Performance

- Extending the life of Pickering station to 2024
- Achieving the cost and schedule commitments for the Darlington Refurbishment Project
- Safely and responsibly managing Ontario's nuclear waste
- Establish an organization that positions Darlington to achieve Top Quartile operational and financial performance
- Execute Pickering SAFSTOR project and transition to decommissioning




## Key Strategic Goals

2017–2019

### OPERATIONAL EXCELLENCE

- Protecting the health and safety of workers, public, environment, and plant.
- Establishing an Equipment Reliability Centre of Excellence to support sustainable reliability of our Nuclear stations.

### PROJECT EXCELLENCE

- Integrating and executing the Darlington Unit 2 Refurbishment on schedule and budget.
- Improving project outcomes across the enterprise through the Project Management Centre of Excellence.

### FINANCIAL STRENGTH

- Focusing on outage performance to meet our generation commitments.
- Optimizing inventory levels while ensuring availability of critical parts.
- Completing assessments to enable extending Pickering operations to 2024.

### SOCIAL LICENCE

- Complying with all applicable laws, codes, and regulations.
- Ensuring safety of the public and environment and reducing tritium emissions as low as reasonably achievable.
- Strong community and stakeholder relations.

## APPENDIX 6: RENEWABLE GENERATION & POWER MARKETING FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | | |
| Regulated Hydroelectric | 192 | 199 | 193 | 194 | 205 | 206 |
| Contracted Generation Portfolio | 99 | 112 | 112 | 114 | 104 | 105 |
| Other* (Including Power Marketing) | 25 | 22 | 16 | 18 | 18 | 18 |
| **Total Base OM&A** | **316** | **333** | **321** | **326** | **327** | **329** |
| Regulated Hydroelectric | 44 | 71 | 95 | 96 | 107 | 98 |
| Contracted Generation Portfolio | 11 | 13 | 16 | 11 | 14 | 6 |
| **Total Project OM&A** | **55** | **84** | **111** | **107** | **121** | **104** |
| Regulated Hydroelectric | 236 | 270 | 287 | 290 | 312 | 303 |
| Contracted Generation Portfolio | 110 | 125 | 129 | 125 | 118 | 111 |
| Other* (Including Power Marketing) | 25 | 22 | 16 | 18 | 18 | 18 |
| **Total RG&PM OM&A** | **370** | **417** | **432** | **433** | **448** | **433** |
| **Capital** | | | | | | |
| **Sustaining** | | | | | | |
| Regulated Hydroelectric | | | | | | |
| Sir Adam Beck Pump GS Reservoir Rehabilitation | 40 | 7 | - | - | - | - |
| Sir Adam Beck I GS Canal Liner Rehabilitation | - | | 1 | 1 | 62 | 62 |
| Other Sustaining Projects | 109 | 125 | 111 | 120 | 153 | 133 |
| **Total Regulated Hydroelectric** | **149** | **132** | **112** | **122** | **215** | **195** |
| Contracted Generation Portfolio | | | | | | |
| Lower Mattagami Dam Safety (formerly Adam Creek Spillway) | - | 5 | 145 | 145 | 5 | - |
| Other Sustaining Projects | 39 | 32 | 32 | 24 | 11 | 6 |
| **Total Contracted Generation Portfolio** | **39** | **37** | **177** | **169** | **16** | **6** |
| **Total Sustaining Capital** | **188** | **169** | **289** | **291** | **231** | **202** |
| **Development Capital** | | | | | | |
| Peter Sutherland Sr. GS (excl. Support Services) | 144 | 41 | 5 | - | - | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 2 | 17 | 43 | 27 | - |
| Lower Mattagami River Project (excl. Support Services) | 16 | - | - | - | - | - |
| Ranney Falls GS Expansion | - | 33 | 18 | 8 | - | - |
| Nanticoke Solar Project | - | 4 | 95 | - | - | - |
| **Total Development Capital** | **160** | **79** | **135** | **50** | **27** | **-** |
| **Total RG&PM Capital** | **348** | **248** | **424** | **341** | **258** | **202** |
| **Thermal Decommissioning Provision Expenditures** | **16** | **50** | **40** | **7** | **10** | **2** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel** | **386** | **386** | **404** | **393** | **381** | **380** |
| Regulated Hydroelectric (net of SBG losses)** | 322 | 331 | 344 | 338 | 327 | 321 |
| Contracted Generation Portfolio | 62 | 53 | 60 | 54 | 54 | 58 |
| Other | 1 | 2 | 0 | 0 | 0 | 0 |

* Includes $8M to $10M per year for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $324M in 2016, $348M in 2017, $357M in 2018, $350M in 2019, $331M in 2020, and $324M in 2021.

## Operational Targets

The key 2017-2019 RG&PM targets designed to drive continuous performance are set out below.

| | Forecast | Business Plan | | |
|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 |
| **All Injury Rate** *(#/200k hrs worked)* | 2.06 | 0.90 | 0.65 | 0.40 |
| **Environment** | | | | |
| Significant Environmental Events (incl. Category A and B Spills) | - | - | - | - |
| Category C Spills | 7 | 9 | 9 | 9 |
| Environmental Infractions | 7 | 8 | 8 | 8 |
| **Capacity** *(MW)* | **9,898** | **9,920** | **9,952** | **10,076** |
| Regulated Hydroelectric | *6,421* | *6,433* | *6,433* | *6,509* |
| Contracted Generation Portfolio (Hydro, Thermal and Solar) | *3,475* | *3,485* | *3,517* | *3,565* |
| Wind (No Contract) | *2* | *2* | *2* | *2* |
| **Hydroelectric Availability** *(%)* | **88.0** | **86.6** | **89.7** | **88.6** |
| Regulated Hydroelectric | *89.1* | *87.3* | *90.0* | *90.7* |
| Contracted Generation Portfolio Hydroelectric | *80.6* | *82.6* | *87.8* | *75.3* |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **2.3** | **1.9** | **1.7** | **1.6** |
| Regulated Hydroelectric | *1.9* | *1.7* | *1.7* | *1.7* |
| Contracted Generation Portfolio Hydroelectric | *5.7* | *3.4* | *2.1* | *1.5* |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | **2.3** | **5.1** | **5.1** | **5.1** |
| **Total Hydroelectric Generating Cost per MWh*** *($/MWh)* | **25.1** | **26.4** | **30.1** | **30.3** |

* Calculated assuming no production is foregone due to SBG losses

## Initiatives

The RG&PM business unit continues to focus on performance excellence, while continuing to drive for efficiency improvements through the following strategic initiatives:

- **Safety:** This initiative will focus on driving improvements in medical treatment injuries through stringent All Injury Rate targets.
- **Workforce Planning and Resourcing Efficiency:** This initiative will focus on resource planning with an emphasis on filling required positions. RG&PM will continue to review positions as they become vacant and challenge whether they are required. Attrition in engineering is being addressed through the re-introduction of the graduate engineer training program and the hiring of additional temporary senior engineers, to address shortfalls in the short term.
- **Environment:** This initiative aims to continue good environmental performance through programs such as the Management Self-Assessment on Drainage Surveys and support of the corporate environmental management system.
- **Project Excellence:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Operational Excellence:** This initiative focuses on sustaining hydroelectric availability and the thermal Equivalent Forced Outage Rate (operating) across the business plan period, as per targets and contractual limits, to ensure unit availability during the Darlington refurbishment.
- **Building Leadership Capability:** This initiative focuses on building strategic leadership capability, continuous improvement in succession planning, engagement in the company-wide leadership development program, mentoring of high potential individuals, and continuing to strengthen and develop partnerships with host communities and Indigenous communities.
- **Productivity Improvements:** This initiative focuses on continued review of opportunities for efficiency gains from strategic initiatives, optimizing the productivity of maintenance staff, and focusing on the Attendance Support Program.
- **Regionalization:** This initiative will continue to explore further efficiencies through regionalization.

## APPENDIX 7: BUSINESS AND ADMINISTRATIVE SERVICES FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **OM&A** | | | | | | |
| Chief Information Officer | 118 | 120 | 119 | 121 | 122 | 121 |
| Real Estate | 96 | 99 | 99 | 101 | 102 | 107 |
| Supply Chain | 53 | 56 | 56 | 57 | 58 | 60 |
| SVP Office | 1 | 1 | 1 | 1 | 1 | 1 |
| **Base OM&A** | **267** | **277** | **275** | **280** | **283** | **289** |
| Chief Information Officer | 30 | 16 | 15 | 14 | 15 | 14 |
| Real Estate | 2 | 5 | 5 | 5 | 6 | 5 |
| **Project OM&A** | **32** | **22** | **20** | **19** | **21** | **19** |
| **Total BAS OM&A** | **298** | **299** | **295** | **300** | **305** | **309** |
| **Capital** | | | | | | |
| Chief Information Officer | 41 | 30 | 26 | 26 | 26 | 26 |
| Real Estate | 18 | 18 | 11 | 12 | 8 | 8 |
| Darlington Refurbishment Project | 20 | 22 | 19 | 18 | 17 | 18 |
| **Total BAS Capital** | **79** | **70** | **56** | **56** | **51** | **52** |
| **Nuclear Waste Provision Expenditures** | **3** | **5** | **5** | **5** | **6** | **6** |
| **Non-Electricity Generation Gross Margin** | | | | | | |
| Non-Electricity Generation Revenue | (87) | (57) | (52) | (43) | (40) | (44) |
| Cost of Goods Sold | 19 | 11 | 9 | 9 | 9 | 9 |
| **Total BAS Non-Electricity Generation Gross Margin** | **(68)** | **(46)** | **(43)** | **(34)** | **(31)** | **(35)** |

## Operational Targets

Business and Administrative Services (BAS) comprises the Company's centralized Supply Chain, Chief Information Office, and Real Estate Services functions. The key 2017-2019 targets for BAS include the following:

| | Forecast | Business Plan | | |
|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 |
| **Employee Safety** | | | | |
| All Injury Rate *(#/200k hrs worked)* | < 0.38 | < 0.35 | < 0.35 | < 0.35 |
| Lost Time Injuries | 0 | 0 | 0 | 0 |
| Total Sick Days per Employee Annualized *(days)* | 13.5 | 12.4 | 11.9 | 11.4 |
| **Environment** | | | | |
| Category C Spills | 1 | 1 | 1 | 1 |
| Environmental Infractions | 3 | 3 | 2 | 2 |
| Waste Diversion Target *(%)* | ≥ 80 | ≥ 80 | ≥ 80 | ≥ 80 |
| **Supply Chain** | | | | |
| Unplanned Nuclear Generation Loss Due to Vendor Quality *(days)* | 14.0 | 12.5 | 12.0 | 12.0 |
| Scope Removal due to Unavailable Parts - Nuclear *(%)* | DN=3.0<br>PN=1.8 | 10% of outage scope variance target | | |
| Stock-out Nuclear Materials (Critical 1 & 2 Parts) *(%)* | 1.8 | 1.3 | 1.0 | 1.0 |
| Strategic Sourcing (value improvement on addressable spend) *($m)* | 52.0 | 12.0 | 11.0 | 7.0 |
| Supply Chain Achievement of Projects Business Unit Milestones *(%)* | 100 | 100 | 100 | 100 |
| **Information Technology *(%)*** | | | | |
| Critical IT System Availability | 99.98 | 99.98 | 99.98 | 99.98 |
| Cyber Security Capability Health *(% Adherence to Plan)* | N/A | 98 | 98 | 98 |
| IT Projects Benefits Realization | 98 | 98 | 98 | 98 |
| IT Execution Phase Project Adherence (Portfolio) | 95 | 95 | 95 | 95 |
| **Real Estate** | | | | |
| Cost Performance Index LTD Active Projects | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 |
| Schedule Performance Index LTD Active Projects | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 |

## Initiatives

Key initiatives of BAS focus on delivering cost effective, value added services in support of generation business unit operations and projects, while continuing to improve efficiency. The initiatives include:

- **Strategic Sourcing**: Supply Chain will maximize OPG spend leverage through a re-compete sourcing strategy and enhanced spend category management to achieve a targeted $30 million value improvement over the business planning period.
- **Project and Contract Management Excellence**: Supply Chain, in collaboration with operating business units, will establish and execute an enterprise-wide model for project and contract management, leveraging industry best practices. This will include establishing a Centre of Excellence to provide leadership and oversight for governance, reporting, systems and tools, and training and development.
- **Supplier Quality and Counterfeit, Fraudulent and Sub-Standard Parts**: While Supply Chain has established effective programs for managing these risks, continuous improvement opportunities will continue to be identified through self-evaluation, benchmarking and third party review. In addition, Supply Chain will expand supplier quality programs to mitigate risk exposure from counterfeit, fraudulent and suspect items across second and third tier sub-suppliers by the fourth quarter of 2018.
- **IT Innovation Strategies and Technology Investments:** Chief Information Office will continue to leverage new IT technologies and automate business processes to deliver operational productivity and cost efficiency improvements.
- **Information Management Optimization Strategy:** Chief Information Office will advance the use of electronic records to transition to a common records and document management system to reduce costs and improve services to less than 5 days by November 2018.
- **Cyber Security:** Chief Information Office will continue to implement the 8-point cyber security program to better ensure OPG remains vigilant, secure and resilient against growing and emerging threats. This is in direct support of the OPG Board Policy on Cyber Security.
- **Strategic Long-Term Accommodation Plan:** Real Estate & Services will partner with business units across OPG to develop a long-term accommodation strategy to optimize owned and lease premises.
- **Infrastructure Life Cycle Planning:** Real Estate & Services will undertake an initiative to optimize infrastructure capital investment through life cycle planning to maintain aging assets and facilities.

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

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November 28, 2016

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2017-2019 Business Plan (the Plan) which was approved by the Board at its meeting on November 10, 2016, in fulfillment of our 2015 Memorandum of Agreement.

In addition to the customary 3-year period of 2017-2019, the Plan includes a financial projection for the 2020-2021 period, similar to last year's Plan. The additional 2-year period is being provided in support of OPG's current rate application to the Ontario Energy Board (OEB) covering the 2017-2021 period. The rate application is currently in progress. The Plan reflects comments from your concurrence letter on OPG's 2016-2018 Business Plan.

***Highlights of the 2017-2019 Business Plan:***

Overall, the 2017-2019 Business Plan is largely unchanged in terms of commitments for Net Income, Total Shareholder Return and the impact to consumers.

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| Net Income Attributable to the Shareholder *($ millions)* | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Total Return to Shareholder ($ millions) | 925 | 975 | 1,186 | 1,228 | 1,549 | 1,590 |
| Return on Equity *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Enterprise Total Generating Cost per MWh *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 79.2 | 72.5 | 74.0 | 74.2 | 72.0 | 69.8 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Capital Expenditures *($ millions)* | 1,739 | 1,778 | 1,905 | 1,854 | 1,662 | 1,559 |
| Headcount from Ongoing Operations | 9,009 | 9,312 | 9,267 | 9,178 | 9,024 | 8,902 |
| Average Impact of 2017-2021 Rate Application on Residential Customer's Monthly Bill | N/A | Average increase of ~$1.05/month annually for 2017-2021 | | | | |

The 2016-2018 Business Plan formed the basis of OPG's rate filing with the OEB. Many of those assumptions and inputs continue to be reflected in the 2017-2019 Business Plan, including:

- Due diligence activities in support of continued Pickering operations to 2024;
- Approved budget and schedule for the Darlington Refurbishment project;
- Outcomes of the 2017-2021 rate application effective January 1, 2017, including Hydroelectric rates increasing at less than inflation under incentive regulation and a Nuclear rate smoothing proposal reflecting amendments to O. Reg 53/05 aimed at managing customer bill impacts; and
- Use of United States Generally Accepted Accounting Principles (US GAAP) to report OPG's financial results, including for Provincial consolidation purposes.

Net Income Attributable to the Shareholder and Return on Equity improve over the period as a result of assumed OEB rate outcomes, completion of the first Darlington unit refurbishment, and further cost efficiencies. OPG's forecast contribution to the Shareholder by the Province's fiscal year is as follows:

| | Province's March 31 Fiscal Year | | | |
|---|---|---|---|---|
| *$ millions* | **2017** | **2018** | **2019** | **2020** |
| **Net Income Attributable to Shareholder** | **349** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | |
| GRC: Payable to OEFC & NPC | 321 | 332 | 344 | 343 |
| Property Tax Payable to OEFC | 15 | 18 | 19 | 19 |
| **Total Non Income Tax PILs** | **336** | **350** | **363** | **362** |
| **Income Tax PILs** | **96** | **166** | **135** | **170** |
| **Total Shareholder Return** | **781** | **1,218** | **1,176** | **1,258** |

The 2016-2018 plan assumed the OEB's decision on the rate application would be issued in the first quarter of 2017. Since then, the OEB has outlined the schedule for the proceeding such that the decision is now expected in approximately the third quarter of 2017. This means that the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016/17 fiscal year. However, the net incomes as noted above remain consistent with the previous plan.

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the 2013 LTEP, and include:

- refurbishment of the first *Darlington* unit, which commenced in October 2016;
- completing construction ahead of schedule of the *Peter Sutherland Sr.* hydroelectric station by 2017, in partnership with Taykwa Tagamou Nation;
- expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- completion of dam safety upgrade initiatives at Lower Mattagami; and
- investments in current and *emerging generation technologies* beyond the core generation portfolio, including solar and energy storage developments.

With respect to the Darlington Refurbishment project, OPG is focussed and has put in place the requisite processes and oversight organizations.

In terms of impact to customers, OPG's rate application assumed in the Plan is an increase, on average, of approximately $1.05 per month each year on a typical residential customer's monthly bill over the period to 2021, within the 2013 LTEP assumptions. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 30% to 40% below the average non-OPG cost of electricity in Ontario.

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***Critical Factors in the 2017-2019 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Outcome of Ongoing Rate Application:** OPG is well into the OEB rate application process, with an oral hearing scheduled in mid February 2017. This application is transformational to OPG. Moving to a 5-year rate term, transitioning to incentive regulation for Hydroelectric assets, reflecting the continued operations of Pickering to 2024 and the plans to refurbish and return to service Unit 2 at Darlington, while implementing a rate smoothing proposal brought about through regulation change, and managing the uncertainty of outcomes related to the OEB's generic proceeding on the recovery of pension and OPEB costs are all significant events. While OPG is confident in the evidence it has submitted and the more open and collaborative approach it has adopted through the regulatory process, the outcome of this complicated and multifaceted application is subject to risk and cannot be predicted with certainty. OPG believes that the outcomes reflected in the Plan are realistic.

- **Delay in Effective Date of OPG's Rates:** Consistent with the previous plan, the 2017-2019 Business Plan assumes that new regulated rates from the application process are effective at the start of 2017. It is within the OEB's authority to set a later effective date, which would have a negative impact of approximately $60 million per month to OPG's net income for the 2017/18 fiscal year.

- **Pickering Continued Operations:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering units to the 2022/2024 period with CNSC approval. The IESO and OPG conducted separate economic evaluations, both of which concluded that extending Pickering has value to Ontario electricity consumers of approximately $600 million. Continuation of Pickering operations also results in a lower smoothed OPG nuclear rate over the Darlington refurbishment period for consumers and employment for several thousand people in and around Pickering while reducing $CO_2$ emissions. A requirement of the next license renewal hearing for Pickering in 2017 will be confirmation from OPG that the Pickering units will operate to 2022/2024 and the filing of our plan for closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on consumer prices.

- **Risk of Adopting International Financial Reporting Standards (IFRS):** OPG has been working with the Province on the possibility of consolidating results using IFRS as required by the Auditor General of Ontario. Under IFRS, OPG's financial results would be subject to considerably increased volatility, due to IFRS impacts on nuclear liability accounting. OPG also may not be able to establish deferral accounts, including several billion dollars related to nuclear rate smoothing which could result in immediate write-offs. These factors could effectively eliminate OPG's net income in the future. OPG continues to work with the Province on this issue. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

- **Executive Compensation Framework:** As a result of compensation restraint legislation and regulations over the past several years, the Company has been unable to make changes needed to remain competitive and to ensure OPG can continue to attract, align and retain the leadership skills and talent required to operate our plants and deliver successfully on projects such as the $12.8 billion Darlington Refurbishment. OPG has worked with external compensation consultants to develop an Executive Compensation Framework (ECF) targeted at the 50$^{th}$ percentile of market peers that would better position OPG to attract, retain and align the necessary leadership talent. With the 10-year Darlington Refurbishment project moving into execution, it is critical that OPG's ECF be in place for the start of 2017. The Ministry's continued active support for OPG's ECF, and help in securing an amendment to Regulation 304/16 in recognition that there are no public sector comparators for OPG's Authorized Nuclear segment, as well as an application to the President of the Treasury Board for permission to use private and international comparators, is very much appreciated.

  The ECF includes medium term incentives, which are 100% pay at risk. For the 2017-2019 cycle, OPG has established the following medium term measures and targets:

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- Return on Equity (%),
- Total Generating Cost ($/MWh) and
- Progress in execution of Darlington Refurbishment Unit 2.

These measures were selected because they are based on the 2017-2019 Business Plan, are self-funding, support the long term health of OPG, and contribute to sustained growth in shareholder value. It is important that, come January 1, 2017, OPG be able to roll out these measures and targets across the Company.

- **Sale of Head Office:** The process from the sale of the 700 University Avenue and 40 Murray Street properties has commenced. The intent of the Plan is to transfer the full portion of the proceeds equal to the after tax accounting gain on sale to the Province, as directed by the Shareholder. However, should the OEB determine that a portion of the proceeds is to be disbursed to ratepayers instead, the value of the gain transferrable to the Province would be reduced correspondingly.

- **Nuclear New Build:** In line with the 2013 LTEP, the Plan includes investments to continue to maintain the site preparation license granted by CNSC related to the New Nuclear option at the Darlington site. As part of the 2017 LTEP, OPG encourages the Province to develop a dialogue with the Federal government and other provinces on the role for New Nuclear in meeting climate change targets. OPG and Ontario have an opportunity to participate in the deployment of new nuclear technologies with partners willing to invest here with the right signals. This Plan anticipates the investment of funds to begin initial planning and preparation activities related to assessing the feasibility of bringing New Nuclear forward as a longer term option in the Province's energy mix.

- **Credit Rating:** Successful execution of major initiatives and an OEB rate outcome consistent with the 2017-2019 Business Plan should ensure that OPG maintains its investment grade credit rating. However, decisions or events with sustained negative financial consequences over the Plan period would stress the credit assessment metrics.

## ***OPG Could Provide Greater Value to the Shareholder and Customer***

You and the Premier have asked for OPG's assistance in keeping electricity prices as low as possible, and to unlock value from OPG to help the Province address its priorities. OPG is well positioned to do both with Shareholder support for four proposals that put OPG on a more commercial footing. These proposals are not assumed in the 2017-2019 Business Plan, but have the potential to deliver enhanced customer and shareholder value over the long term. We are including them here to ensure that the Ministry is aware of them and look forward to a meaningful dialogue.

1) *Align OPG's Capital Structure with the OEB*

If OPG's capital structure was in line with the OEB deemed capital structure that OPG has proposed in its current rate application of 51% debt and 49% equity, with this plan, OPG would achieve the following higher ROE levels:

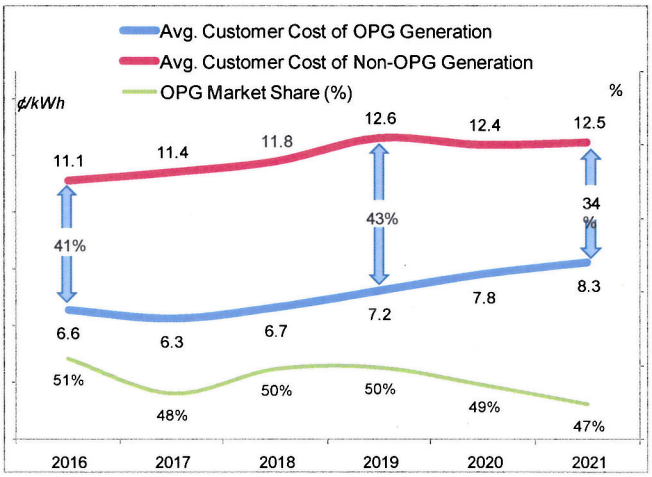
**ROE Assuming OEB Capital Structure**

| | Business Plan | | | Projection | |
|---|---|---|---|---|---|
| | **2017** | **2018** | **2019** | **2020** | **2021** |
| Return on Equity Assuming OEB's Deemed Capital Structure *(%)* | 5.7% | 6.8% | 7.0% | 8.2% | 8.9% |

2) *Invest in Assets to Continue to Mitigate Prices*

Achieving a higher ROE would allow OPG to leverage its expertise in generation and re-invest to maximize generation from existing assets and invest in new unregulated assets to replace 3000 MW of generation from the closure of the Pickering generating station. OPG's market share has declined by about 20% with coal closure, and will shrink further with the closure of Pickering. By replacing those megawatts, OPG would direct a portion of the additional capital into suitable investment options in order to increase the Shareholder's value of the Company.

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In addition, OPG would be able to maintain a critical size and continue to mitigate prices for customers some 30% to 40% below other generators. Working with the Shareholder OPG would explore options for investments in the near term, ensuring that these investments provide value to customers and the Province and do not distract from our current Plan. OPG has already successfully made more than $5 billion in investments in clean, renewable technologies undertaken over the past decade. Those investments have not only supported Ontario's climate change initiatives but have generated returns that represent a notable share of OPG's net income. We can do more.

3) *Pay Dividends to Fund Government Priorities*

OPG has also proposed the establishment of a dividend program tied to key business outcomes, including a successful OEB rate outcome and Darlington Unit 2 refurbishment that could return to the Shareholder $2.4 billion, which the Province could use to target its priorities – this could be lowering prices for electricity or investing in infrastructure.

*Illustrative Dividend Program – not in the 2017-2019 Business Plan*

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|---|---|---|
| Leverage to 51% | Debt Ratio | 34% | 39% | 40% | 42% | 42% | 41% | |
| | Net Income Attributable to Shareholders ($M) | 438 | 494 | 659 | 694 | 832 | 938 | 4,056 |
| | ROE target | 4.2 | 4.9 | 6.1 | 6.3 | 7.4 | 8.0 | |
| | Dividend | 0 | 620 | 400 | 500 | 400 | 500 | 2,420 |

Dividend payments would assist OPG in achieving a more balanced capital structure and would also provide for a more predictable and steady future cash flow. As shown in the table above, ROE improves as the leverage transitions toward the deemed capital structure used by the OEB. On this path, a 9% ROE of would be achieved post completion of Darlington Refurbishment .

4) *Use OPG Public Debt to Reduce Provincial Debt*

To establish the dividend program and to drive greater commercial behaviours to the benefit of customers and the Shareholder, OPG has proposed to replace financing from the Ontario Electricity Financial Corporation with a public financing strategy for a portion of OPG's corporate debt. This debt program could start small and grow over time as OPG produced results. OPG could remove approximately $6 billion from the Province's debt by 2021 which includes the refinancing of maturing debt and future additional funding requirements. OPG has had significant success with $2.2 billion in various project financing in external markets. Additional benefits include supporting the OEB's capital structure, driving a level of discipline and commercial orientation within the Company, accessing new debt investors and supporting OPG's ability to retain the exemption from the Ontario Securities Commission to remain on US GAAP.

In closing, OPG's 2017-2019 Business Plan and the financial projection for the 2020-2021 period set ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG will achieve this while focussed on the successful execution of Darlington refurbishment. . We look forward to further dialogue on the proposals we have described above that are not currently in the Business Plan but could enhance customer and shareholder value.

Sincerely,

Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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November 10, 2016

# OPG's 2017-2019 BUSINESS PLAN

## DECISION REQUIRED

The purpose of this submission is to seek the Board's approval of OPG's 2017-2019 Business Plan, including a financial projection for the 2020-2021 period. Upon Board approval, the business plan will be submitted to the Shareholder for review and concurrence in accordance with the Memorandum of Agreement between the Shareholder and OPG.

## ISSUE

OPG's 2017-2019 Business Plan implements the Company's strategic objectives by setting out performance targets and resource levels associated with meeting key business outcomes over the next several years. The business plan includes the budget for the 2017 year, which establishes the operational and financial control base against which actual results will be measured.

The business plan supports OPG's 5-year hydroelectric and nuclear rate application to the Ontario Energy Board (OEB) filed in May 2016. The rate application covers the 2017-2021 period and, for the nuclear operations, was based on the forecast of costs and production from the 2016-2018 Business Plan. The 2016-2018 Business Plan was approved by the Board in May 2016 and included a financial projection for 2019-2021. The 2017-2019 Business Plan will be used to update the rate application for material plan-over-plan changes and therefore includes a financial projection for 2020-2021. The OEB's decision on OPG's rate application is expected during the third quarter of 2017. The 2017-2019 Business Plan assumes that new regulated rates are made effective January 1, 2017.

## ANALYSIS

### Overview

OPG's business plan is focused on increasing value to the Shareholder, while continuing to act as a mitigator for customer price increases and supporting provincial policy objectives focused on the decarbonisation of the power sector and the broader economy. The plan meets the objectives of Ontario's 2013 Long-Term Energy Plan (LTEP). Future business plans will reflect any changes from the updated LTEP expected to be issued in 2017.

As OPG's operating and regulatory environment has not changed substantially during 2016, the objectives and results of the 2017-2019 Business Plan are consistent with the 2016-2018 Business Plan. In particular, the business plan continues to reflect resource and outage plans in support of achieving safe and reliable operations at Pickering to 2024 and successful execution of the Darlington refurbishment, in line with the approved budget and schedule including the Unit 2 cost estimate approved by the Board in August 2016. The plan also reflects OPG's efforts to close the staffing gap in key areas through resourcing strategies including selective hiring, while continuing to leverage attrition in other areas.

Consistent with the previous plan, the 2017-2019 Business Plan projects net income growing to ~$730 million in 2019 and ~$1 billion in 2021. This reflects regulated rate increases consistent with OPG's May 2016 rate application, on the basis of a custom incentive regulation approach with rate smoothing for the nuclear operations and an incentive ratemaking formula for the hydroelectric operations. The rate application results in average increases of ~0.7% or ~$1.05 per month annually on a typical residential customer's monthly bill, with the overall customer cost of OPG's generation continuing to track considerably below that of other generators in Ontario. Management believes that the forecast credit metrics and operating cash flow levels in the plan that result from the proposed rate increases should continue to

support OPG's current investment grade credit rating. The execution of the business plan will allow OPG to contribute ~$3.4 billion in earnings and taxes to the Shareholder over the 2017-2019 period.

The plan reflects the completion of the Peter Sutherland Sr. hydroelectric generating station (GS) in 2017 and the Nanticoke solar facility in 2019, both of which will contribute positively to earnings. The plan also reflects the estimated impact of the 2017 Ontario Nuclear Funds Agreement (ONFA) Reference Plan update, which is subject to approval by the Minister of Finance. The updated reference plan will reduce customer rate impacts, and improve operating cash flow by reducing segregated fund contributions. In addition, the plan assumes closing of the sale of OPG's head office property in the second quarter of 2017, with the portion of the proceeds equal to the after-tax accounting gain on the sale transferred to the Province, as directed.

Return on equity (ROE) is projected to increase from 4.2% in 2016 to 7.3% by 2021, but continues to fall short of the OEB-allowed regulated rate of return of ~9%. Through ongoing discussions with the Shareholder, OPG has developed a strategy to migrate the capital structure to reduce equity and increase debt, with a view to pursuing a public debt offering strategy in conjunction with a focused growth strategy. This would help OPG to move toward a 9% ROE. The strategy is subject to the Shareholder's concurrence, and therefore is not yet reflected in the business plan. As such, OPG's planned debt ratio remains in the range of approximately 31% to 37%, well below OEB-approved levels of over 50%. As shown below, if OPG's actual capital structure reflected the deemed debt ratio of 51% proposed in OPG's rate application, ROE of ~9% would be achievable by the end of the planning period.

The business plan is highly dependent on the outcome of OPG's OEB rate application and OEB decisions related to the recovery of pension and other post-employment benefit (OPEB) costs on an accrual basis. Different regulatory outcomes from those assumed in the plan could significantly lower net income, cash flow, and returns to the Shareholder, leading to higher borrowing requirements and increased risk to OPG's credit rating. This may in turn necessitate curtailment of project or other expenditures. In particular, the plan assumes that new regulated rates pursuant to the rate application are made effective as of January 1, 2017. A delay in this effective date could have significant adverse impacts on 2017 net income and future cash flow, largely due to the nuclear generation shortfall relative to existing rates, as a result of Darlington Unit 2 being offline for refurbishment. The plan also assumes that the OEB provides necessary assurance over future recovery of differences between pension and OPEB accrual and cash amounts, and associated income tax impacts.

Highlights of the 2017-2019 Business Plan, including the financial projection for the 2020-2021 period, are as follows:

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to the Shareholder *($ millions)* | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Return on Equity *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Enterprise Total Generating Cost per MWh *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 79.2 | 72.5 | 74.0 | 74.2 | 72.0 | 69.8 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Capital Expenditures *($ millions)* | 1,739 | 1,778 | 1,905 | 1,854 | 1,662 | 1,559 |
| Headcount from Ongoing Operations | 9,009 | 9,312 | 9,267 | 9,178 | 9,024 | 8,902 |
| Average Impact of 2017-2021 Rate Application on Residential Customer's Monthly Bill | N/A | Average increase of ~$1.05/month annually for 2017-2021 | | | | |

If OPG's actual capital structure was in line with the OEB deemed capital structure of 51% debt and 49% equity proposed in the rate application, OPG would plan to achieve the following higher ROE levels:

| | Business Plan | | | Projection | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Return on Equity Assuming OEB's Deemed Capital Structure *(%)* | 5.7% | 6.8% | 7.0% | 8.2% | 8.9% |

**Key Assumptions and Risks**

- Planned activities carried out over the 2017-2020 period successfully enable Pickering continued operations beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operations beyond 2020 would result in a reduction to planned generation revenues and cash flow and the advancement of employee severance and station decommissioning expenditures. Extending Pickering operations has a moderating effect on OPG's nuclear rates.
- The Darlington refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.
- New regulated rates are effective January 1, 2017. An OEB decision that delays this effective date would result in a ~$50 million to $60 million reduction in net income per month. In addition, new rates established by the OEB that are lower than those requested by OPG may not provide for recovery of all costs of OPG's regulated operations or may not allow for an appropriate rate of return.
- Pension and OPEB costs allowed in the 2017-2021 nuclear rates are limited to cash amounts, with the difference between accrual and cash amounts (for nuclear and hydroelectric) continuing to be recorded in a deferral account. The OEB provides necessary assurance over future recovery of these amounts, including associated taxes, through the ongoing generic proceeding on this issue or otherwise. An OEB decision that leads to a write-off of the deferral account balance would result in material net income reductions of over ~$600 million over the planning period.
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations could adversely impact the successful execution of these projects and other strategic imperatives.
- OPG continues to report its financial results in accordance with United States generally accepted accounting principles (US GAAP) and the OEB continues to rate regulate OPG on that basis. Adoption of International Financial Reporting Standards (IFRS), either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements using US GAAP or the Shareholder's requirement to consolidate OPG's results under IFRS, is expected to cause significant volatility in OPG's net income compared to US GAAP. Currently, IFRS does not adequately address a rate regulated environment.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2017-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2. A discussion of the 2017-2019 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Operational Excellence

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost. The business plan reflects funding and staffing levels aimed at achieving top performance at the Darlington nuclear station, maximizing the value of the Pickering nuclear station by continuing its safe and reliable operation to 2024, and maintaining strong cost-effective performance at OPG's hydroelectric and thermal facilities. Performance targets for safety and reliability over the planning period will continue to drive operational excellence.

| Total Generating Cost* | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *($/MWh)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Enterprise | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| Nuclear | 63.2 | 75.6 | 74.6 | 74.5 | 77.1 | 77.3 |
| Hydroelectric | 25.1 | 26.4 | 30.1 | 30.3 | 30.0 | 29.0 |

* Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures) divided by OPG generation adjusted for surplus baseload generation losses

The business plan builds on efficiencies achieved to date, with a focus on pursuing further opportunities for cost effectiveness improvement across the generating business units and support services. In 2016, OPG adopted Total Generating Cost (TGC) per MWh as an enterprise-wide measure of operational cost effectiveness, in addition to TGC per MWh metrics for each of the Nuclear and Hydroelectric operations. Enterprise-wide targets for TGC per MWh range from approximately $55/MWh to $57/MWh over the 2017-2021 period. The increase in the TGC over the planning period reflects lower nuclear production levels as a result of the Darlington refurbishment outages, as well as higher capital expenditures due to two large hydroelectric projects – the Lower Mattagami dam safety upgrade and the Sir Adam Beck I GS power canal liner rehabilitation. The TGC targets are adjusted for hydroelectric generation losses due to surplus baseload generation conditions.

A prominent feature of the OEB's incentive regulation framework is to encourage productivity savings. In particular, for the hydroelectric business, OPG's application requests regulated rates that reflect annual increases of less than inflation. For the nuclear business, OPG's application includes a stretch factor that reduces recoverable OM&A expenses below planned levels. This will challenge OPG to find additional cost savings within its operations, beyond those already reflected in planned cost levels. In order to improve profitability, OPG must identify and implement such additional efficiency improvements starting as early as 2017, with cost savings growing over time.

Benchmarking studies have indicated that OPG has reduced the gap to the average nuclear staffing benchmark from 17% in 2011 to 4% in 2014. With further sustained headcount reductions since 2014, OPG is confident that its current and planned nuclear staffing levels are at the benchmark level. OPG also benchmarks the costs of the Pickering and Darlington stations against other nuclear stations. On a per unit, basis, OPG's all-in operating and capital expenditures for the stations continue to be amongst the lowest in the industry. OPG's nuclear stations will continue to target strong reliability performance, including a top-quartile forced loss rate performance of 1.0% for the Darlington station and a 5.0% forced loss rate for the Pickering station consistent with planned investment levels, for the 2017-2019 period. The operational targets and associated initiatives for the Nuclear business unit are found in Appendix 4, with OPG's Nuclear strategic planning framework included in Appendix 5.

The hydroelectric stations continue to exhibit strong cost effectiveness performance, with regulated fleet operating costs, excluding Gross Revenue Charge (GRC) payable to the Province, benchmarking in the second quartile relative to peers. Operating targets for 2017-2019 include strong fleet-wide hydroelectric availability factors averaging 88.3% per year. The operational targets and associated initiatives for the Renewable Generation & Power Marketing (RG&PM) business unit are found in Appendix 6.

The operational targets and associated initiatives for OPG's centre-led Business and Administrative Services organization, which is focused on providing cost effective information technology, supply chain and real estate services in support of business priorities, are found in Appendix 7.

**Production**

Total planned OPG production ranges from 72.5 TWh to 74.2 TWh per year over the 2017-2019 period, down from 79.2 TWh forecast in 2016 and declining to 69.8 TWh in 2021. This reflects a declining trend in the Darlington production due to refurbishment outages starting in October 2016, including a partial overlap starting in 2021 between the second and third unit refurbishments.

The following other main factors affect the variability in the planned nuclear production over the period:

- Incremental planned outage days at the Pickering station to enable continued operations in line with the business case approved by the Board in November 2015;
- Single Fuel Channel Replacement outage work at the Pickering station in 2019 and at the Darlington station in 2017 and 2020;

- Initial increase in the forced loss and planned outage days expected at the Darlington station as the first refurbished unit returns to service in early 2020; and
- Pickering VBO in 2021 requiring the shutdown of all units for the duration of the outage.

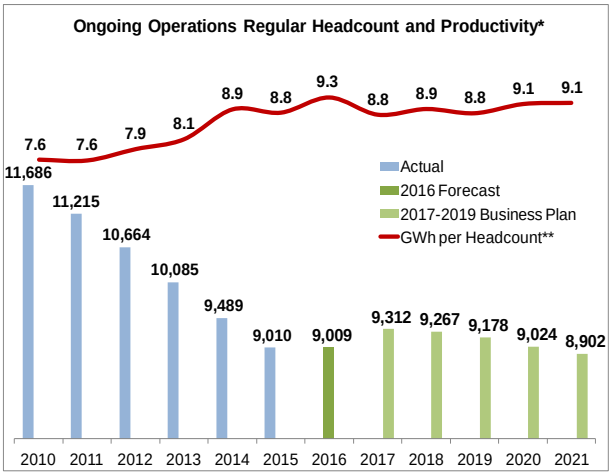
The following are the main drivers of the forecast hydroelectric production for the period:

| Production (TWh) | Forecast 2016 | Business Plan 2017 | Business Plan 2018 | Business Plan 2019 | Projection 2020 | Projection 2021 |
|---|---|---|---|---|---|---|
| Darlington | *25.8* | *19.1* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *20.1* | *19.1* | *19.2* | *19.4* | *19.6* | *18.8* |
| Total Nuclear | 45.9 | 38.1 | 38.5 | 39.0 | 37.4 | 35.4 |
| Regulated Hydroelectric | 30.5 | 31.2 | 32.2 | 32.0 | 31.2 | 30.8 |
| Contracted Generation Portfolio | 2.7 | 3.1 | 3.3 | 3.2 | 3.4 | 3.5 |
| **Total Production (Net of SBG Losses)** | **79.2** | **72.5** | **74.0** | **74.2** | **72.0** | **69.8** |
| Regulated Hydroelectric SBG Losses | 4.0 | 1.3 | 1.0 | 0.9 | 0.3 | 0.3 |
| Contracted Plant SBG Losses | 0.4 | 0.3 | 0.3 | 0.3 | 0.2 | 0.1 |
| Total SBG Losses | 4.5 | 1.7 | 1.2 | 1.2 | 0.5 | 0.4 |

- Anticipated improvement in surplus baseload generation conditions during the planning period, largely driven by nuclear refurbishment outages;
- A major unit overhaul outage at the DeCew II GS in 2017;
- A series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over 2017-2019;
- Outages at the Sir Adam Beck I GS to rehabilitate the forebay and crossover canal in 2020 and the power canal liner over 2020 and 2021; and
- Production from the newly online Peter Sutherland Sr. GS starting in 2017 and lower production from the Lower Mattagami units in 2016 due to transmission system unavailability and an extended planned outage.

**Headcount**

The downsizing efforts from OPG's Business Transformation initiative have been successful in achieving significant attrition-based headcount reductions across the organization since 2011, with cumulative savings from the reductions reaching $1 billion in 2016. However, continuing high levels of attrition reflecting employee demographics are necessitating increased hiring to fill key vacancies in certain areas (particularly in the Nuclear business unit). To address this gap and in light of the decision to pursue extended Pickering operations beyond 2020, OPG has modified resourcing plans and staffing models, taking into consideration the current need for qualified staff while seeking to minimize the financial impact of future downsizing programs associated with the planned Pickering end of life in 2024.




* Excludes Darlington refurbishment headcount

** Production is normalized by adding back hydroelectric surplus baseload generation losses and, in 2017 - 2021, the lower production due to the Darlington refurbishment outages

Through these efforts, OPG has hired ~500 regular (full-time) employees (excluding Darlington refurbishment) between January 2016 and the end of September 2016, and is actively continuing to ramp up recruitment and on-boarding efforts to attract the necessary talent. In addition, to date OPG has hired ~60 Term Employees, a new category of non-regular employees negotiated with the Power Workers' Union (PWU) through collective bargaining in 2015, with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. OPG is targeting to bridge the remaining staffing gap in 2017 by filling open positions, which will increase year-end 2017 regular headcount from ongoing operations by approximately 300, compared to 2016. While planned positions are being filled, work programs are being managed through the selective use of temporary resources and overtime.

After 2017, planned staffing levels from ongoing operations begin to decrease gradually. By the end of 2021, headcount from ongoing operations is expected to be about 100 lower than at the end of 2016 and

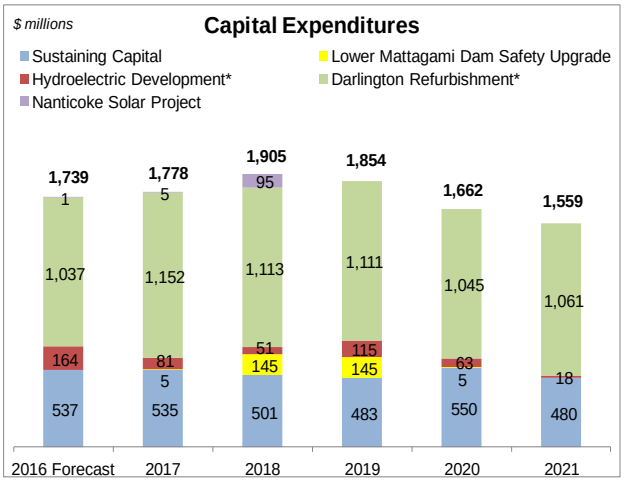
about 400 lower than at the end of 2017. These reductions reflect efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020. Employee productivity, as measured by GWh per headcount, remains relatively stable during the planning period.

The Darlington refurbishment headcount peaks at about 640 during the planning period, compared to about 460 at the end of 2016. This headcount is not considered part of ongoing operations.

## Project Excellence

Asset base growth through development or acquisition is a key element to achieving increased profitability and ROE levels. OPG continues to focus on delivering projects safely, on time, on budget and with high quality. In line with the 2013 LTEP, OPG's capital program is focused on the continued efficient utilization of existing generation assets through sustaining expenditures, the refurbishment of the Darlington units, development of new and existing hydroelectric sites, and the pursuit of other renewable energy opportunities. The upcoming 2017 LTEP may or may not support OPG's pursuit of additional investment opportunities.

Total annual capital expenditures range between ~$1.8 billion and ~$1.9 billion per year over the 2017-2019 period and between ~$1.6 billion and ~$1.7 billion in 2020 and 2021. This includes Darlington refurbishment expenditures of between ~$1.0 billion and ~$1.2 billion per year in line with the Board-approved Unit 2 cost estimate, ~$45 million for the completion of the Peter Sutherland Sr. GS for in-service in 2017, and ~$100 million for the construction of the Nanticoke solar facility by 2019.



* Includes expenditures budgeted by Support Services

The first refurbished Darlington unit, Unit 2, is assumed to be returned to service in February 2020 per the high-confidence project schedule, with the second unit refurbishment commencing immediately thereafter and the third unit refurbishment starting in July 2021, assuming any necessary concurrence from the Province is obtained. The planned in-service amount associated with the return to service of Unit 2 is $4.8 billion in February 2020, including costs incurred during the planning phase of the project.

Total sustaining capital expenditures average ~$570 million per year over the 2017-2021 period. This includes Nuclear expenditures in the order of ~$300 million per year to 2020, decreasing to ~$245 million by 2021 as regulatory programs are completed and non-refurbishment capital project work at Darlington is temporarily reduced while two units undergo refurbishment. Pickering expenditures decline over the period in line with the planned end of life in 2024.

Excluding the Sir Adam Beck I GS power canal liner rehabilitation project, regulated hydroelectric sustaining capital expenditures over the 2017-2021 period average ~$130 million per year. This includes a number of projects aimed at maintaining and enhancing availability and reliability of OPG's renewable fleet, including:

- The completion of the Sir Adam Beck Pump GS reservoir rehabilitation in 2017;
- The overhaul and upgrade of the DeCew II GS Unit 2 scheduled for completion in 2018;
- The overhaul and upgrade of Sir Adam Beck I GS Unit 5 in 2018-2019 and Unit 8 in 2020-2021;
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations;
- Rehabilitation of the forebay and crossover canal at the Sir Adam Beck I GS in 2020;
- Flow control equipment replacements in Northwest Operations; and
- Unit overhauls at the Sir Adam Beck Pump GS.

The total expenditures for the power canal liner rehabilitation project at the Sir Adam Beck I GS are projected at ~$125 million over 2020 and 2021. The project will repair concrete deterioration and restore the original flow capacity, ensuring reliable operations for the next 50 years.

Sustaining expenditures also include the Lower Mattagami dam safety upgrade planned for 2018 and 2019, with total expenditures of $300 million. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service.

Other planned generation development projects include the conversion of the Sir Adam Beck Units 1 and 2 to 60 Hz to increase capacity, and the expansion/redevelopment of regulated hydroelectric stations that are approaching end of life by leveraging existing infrastructure (i.e. Ranney Falls, Coniston and Calabogie generating stations). OPG will strategically assess investment in emerging generation technologies beyond the Company's core generation portfolio, including microgrid and energy storage developments, in support of Ontario's climate change strategy and to help position OPG for future growth.

Planned expenditures against previously established provision for nuclear station decommissioning and waste management are planned to increase over the planning period, from close to $300 million in 2016 to $525 million by 2021. The increase over the period reflects the following:

- The Nuclear Waste Management Organization's planned siting process activities for the Adaptive Phased Management used fuel disposal program;
- Expenditures on the Darlington refurbishment nuclear waste containers; and
- Expenditures for proceeding with OPG's proposed low and intermediate level waste deep geologic repository (L&ILW DGR), assuming receipt of a preparation and construction licence.

Eligible nuclear provision expenditures are funded from the nuclear segregated funds.

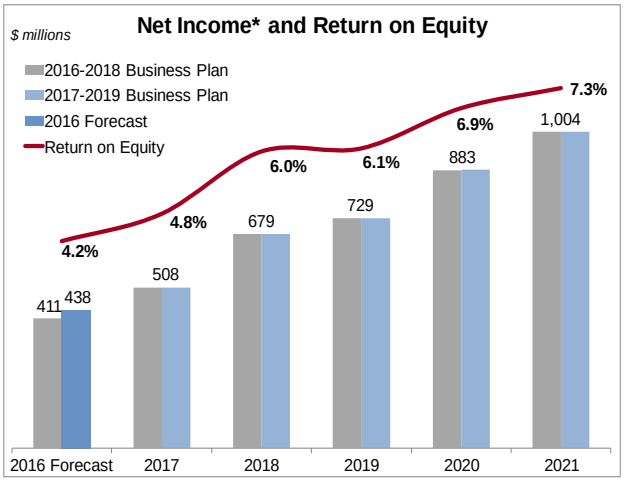
The plan also assumes provision expenditures of $85 million over the period for the decommissioning of the former Nanticoke GS, taking into account the impact on the construction and operation of the Nanticoke solar facility. OPG is in the process of preparing a definition phase plan for this work, which will form the basis for the cost estimate and schedule for the specific decommissioning activities, including demolition.

## Financial Strength

In line with the Company's commercial mandate, OPG's business plan is focused on increasing net income and return on the Shareholder's investment, through higher revenues and a continued focus on efficiency improvements, while ensuring that the Company is able to cost effectively fund its major projects and obligations. In pursuing commercial objectives, OPG takes into account the impact on Ontario electricity customers by continuing to seek further efficiencies in the Company's cost structure.

### Net Income and Return on Equity

Net income attributable to the Shareholder is forecast to increase from $438 million in 2016 to $729 million in 2019, with ROE increasing from 4.2% to 6.1%, respectively. By 2021, net income attributable to the Shareholder is projected to reach ~$1 billion, with an ROE of 7.3%. The 2017-2021 planned net income and ROE levels are unchanged from the previous plan. Although net income and ROE are forecast to improve over the planning period, different regulatory outcomes from those assumed in the plan could result in significantly lower net income and returns to the Shareholder.



* Net Income Attributable to Shareholder

The planned 2017 net income attributable to the Shareholder of $508 million is an improvement over the forecast results for 2016 of $438 million. The increase is primarily a result of:

- New regulated rates assumed to come into effect at the beginning of 2017;
- A gain on the sale of OPG's head office property expected in 2017, net of new leaseback costs and foregone lease income;
- Recognition of regulatory assets for the portion of the nuclear revenue requirement, including associated interest, deferred for future recovery under nuclear rate smoothing starting in 2017; and
- Higher capitalized interest for the Darlington refurbishment capital expenditures.
- These factors are partially offset by higher corporate level charges in 2017, planned outages at Sir Adam Beck I and DeCew II hydroelectric stations in 2017, and a gain recognized in 2016 from the OEB's decision to partially reverse a previous disallowance of Niagara Tunnel project expenditures.

Net income attributable to the Shareholder is planned to increase to $679 million in 2018 and to $729 million in 2019, primarily due to:

- Year-over-year higher capitalized interest for the Darlington refurbishment capital expenditures;
- Fewer outages at the regulated hydroelectric stations compared to 2017;
- Lower corporate level charges compared to 2017; and
- Full year of earnings from the Peter Sutherland Sr. GS starting in 2018 and earnings from the Nanticoke solar facility starting in 2019.
- These factors are partially offset by lower earnings as a result of the gain on the sale of OPG's head office property in 2017.

Net income attributable to the Shareholder is projected to continue to improve beyond 2019, reaching ~$1 billion in 2021, as the first refurbished Darlington unit returns to service and enters rate base in February 2020. This is partially offset by the depreciation of the Pickering rate base, the impact of outages at the Sir Adam Beck I GS related to the rehabilitation work on the forebay and crossover canal as well as the power canal liner, and the expiry of the current Thunder Bay biomass energy supply agreement.

Assurance of recovery of pension and OPEB costs on an accrual basis (including associated taxes) through OEB regulated rates remains a material risk to the business plan. As the generic proceeding related to the treatment of pension and OPEB costs for regulated utilities in Ontario is ongoing, the plan continues to assume that the recovery of pension and OPEB costs for 2017-2021 is limited to cash amounts and that the difference between cash and accrual amounts continues to accumulate in an OEB authorized deferral account (for both nuclear and hydroelectric operations). This is in line with the proposal put forward in OPG's May 2016 rate application. The deferral account balance is projected to accumulate to ~$480 million by the end of 2016, with further additions of ~$150 million over the 2017-2021 period. The future outcome of the OEB generic proceeding or another related OEB decision are expected to determine the recoverability of the deferral account (and associated income taxes). An OEB decision leading to a write-off of the balance would result in a substantial reduction of up to $630 million in net income over the planning period. Write-offs would be recorded in the period the applicable OEB decision is issued.

The plan reflects an updated valuation of OPG's registered pension plan filed with the Financial Services Commission of Ontario in September 2016, as approved by the Board. The valuation was performed as of January 1, 2016 and determined OPG's required cash contributions for 2016 to 2018. Compared to the previous valuation, this reduced OPG's 2016 contributions by about $100 million, while increasing the cash-to-accrual differential recorded in the deferral account for 2016.

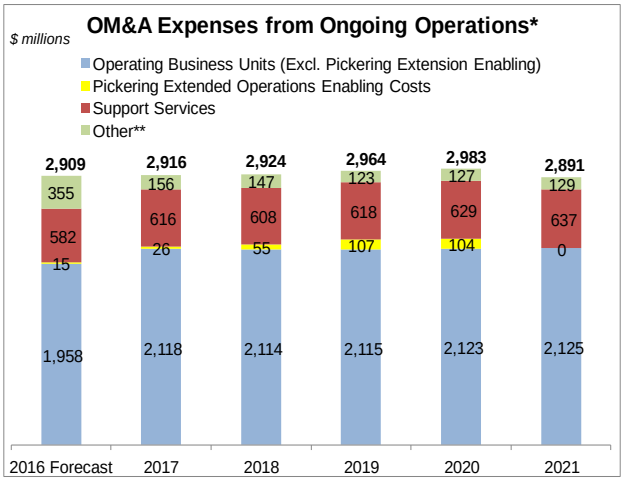
In its 2015-2017 Business Plan concurrence letter, the Shareholder recognized that OPG's existing accrual accounting methods for recovery of pension and OPEB costs are a fair representation of the long-term nature of these liabilities. OPG continues to believe that the accrual accounting basis aligned with OPG's financial accounting requirements is the most appropriate rate recovery basis for the Company's pension and OPEB costs, and has made submissions to this effect through the OEB's generic proceeding.

**Operations, Maintenance & Administration Expenses**

OM&A expenses from ongoing operations, which exclude the impact of regulatory variance and deferral account offsets as well as Darlington Refurbishment project expenses, average ~$2.9 billion per year during the 2017-2019 period, an increase of ~$25 million compared to forecast 2016 expenses. This reflects increases in business unit expenditures across the organization, partly offset by declining pension and OPEB costs. The increases in business unit expenditures are primarily driven by the following:

- Incremental outage and other work program costs to enable Pickering continued operations in line with the business case approved by the Board;

- Changes in nuclear outage scope, including maintenance work on Darlington Unit 2 to be performed during the refurbishment outage that would have otherwise occurred online or during regular outages, and Single Fuel Channel Replacement outage work at Darlington scheduled for 2017;
- Planned external hiring to fill critical staffing gaps and support effective succession planning across the Company;
- Sustaining projects to maintain asset reliability at regulated and contracted hydroelectric stations, including unit overhauls, repair work, and civil structure remediation;
- New drug testing program expected to take effect for the nuclear facilities during the planning period in accordance with CNSC Fitness for Duty regulatory requirements;




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferral account offsets
** Includes centrally held pension /OPEB costs

- Additional maintenance and other work programs at the nuclear stations to maintain asset reliability and address equipment aging issues;
- Labour cost escalation pursuant to collective agreements, and inflationary impacts; and
- Higher nuclear liability insurance requirements pursuant to federal legislation.
- These increases are partially offset by a gradual decline in regular staffing levels after the planned increase in 2017, as well as higher expenses in 2016 associated with inventory obsolescence costs.

OM&A expenses from ongoing operations begin to decrease in 2021, reflecting the following:

- Completion of work programs to enable Pickering continued operations;
- Further reductions in staffing levels, reflecting efficiency improvement initiatives and the impact on work programs from the approaching Pickering end of life;
- Decline in nuclear outage expenses in 2021 as no major outages are planned to occur at the Darlington station in that year, partly offset by the incremental costs of the assumed station-wide Pickering VBO in 2021.

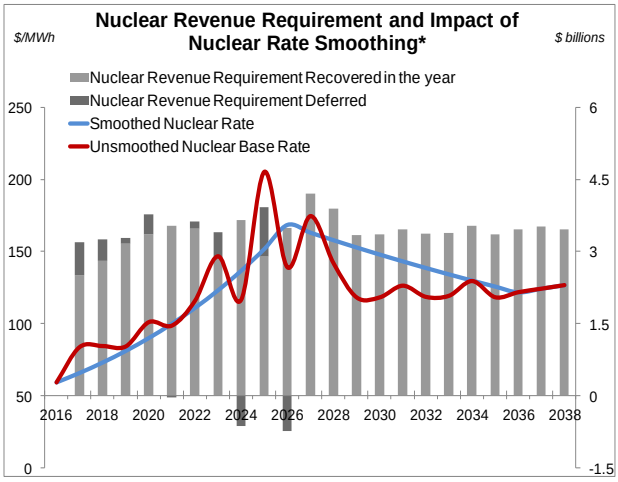
Declining pension and OPEB costs over the period are due to a combination of factors, including: projected pension asset returns, the impact of increased employee contributions, and a recently emergent, more refined US GAAP method for applying discount rates to determine the interest components of pension and OPEB costs that OPG expects to adopt for financial reporting purposes starting in 2017. This approach determines interest costs by applying individual spot rates in the yield curve to each year of cash flows, rather than a single weighted average discount rate determined based on the yield curve. This has the effect of lowering OPG's pension and OPEB costs over the planning period, compared to 2016. The factors decreasing pension and OPEB costs relative to 2016 are partly offset by the reduction in discount rates, from 4.1% for pension and 4.2% for other post retirement benefits at the beginning of 2016 to 3.6% and 3.7%, respectively. The regulated portion of the decreases in pension and OPEB costs is assumed to be offset by the pension and OPEB cash-to-accrual deferral account, resulting in a relatively small overall impact on net income.

The regulatory variance and deferral account offsets to OM&A expenses decline over the planning period. This reflects a narrowing of the differential between pension and OPEB accrual costs and cash amounts that is being recorded in the cash-to-accrual deferral account. The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

**Regulated Rates**

The plan reflects OPG's filed 2017-2021 nuclear and hydroelectric rate application, which results in an estimated average increase in a typical residential customer's monthly bill of ~0.7% or ~$1.05 each year to the end of 2021. Based on the application, the plan assumes annual hydroelectric base rate increases of ~1.5% beginning in 2017, off the existing base rates with some adjustments.

For the nuclear operations, consistent with *Ontario Regulation 53/05*, the rate application includes OPG's 11% per year rate smoothing proposal that avoids large price spikes arising during the Darlington refurbishment and at the end of Pickering operations. Under rate smoothing, the rate application seeks approval of annual nuclear revenue requirements as well as a smoothed rate trajectory for the 5-year period. The difference between the approved revenue requirements and the approved base rate trajectory will be recorded in a deferral account for recovery in the post-refurbishment period. The assumed nuclear rate trajectory from the rate application is below the 2013 LTEP assumptions for OPG's nuclear rates.



* Information beyond 2021 is included for illustrative purposes

In accordance with the regulation, the portion of the approved nuclear revenue requirement deferred for future collection will be determined by the OEB and captured in a deferral account that will earn interest at a long-term debt rate reflecting OPG's long-term borrowing cost as authorized by the OEB, compounded annually. Pursuant to the regulation, the OEB must authorize the recovery of the account balance over a period of up to 10 years beginning at the end of the refurbishment project. The rate smoothing illustration shown assumes recovery of the deferred balance over the 10-year period following the completion of the Darlington refurbishment. Based on the assumed rate trajectory, the deferral account balance, including associated interest, is projected to grow to ~$1.3 billion by 2019 and ~$1.9 billion by 2021. In accordance with US GAAP, rate smoothing deferrals in a given period will be recorded by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Accordingly, the collection of the deferred amounts in future years will not result in additional net income.

Although for planning purposes OPG assumes smoothed nuclear base rate increases of 11% per year for the full Darlington refurbishment period, the determination of the rate trajectory beyond 2021 is not part of OPG's current rate application and will be established by the OEB in the future. Leading up to that period, OPG will continue to focus on improving its cost structure and generation performance.

**Ontario Nuclear Funds Agreement Reference Plan Update**

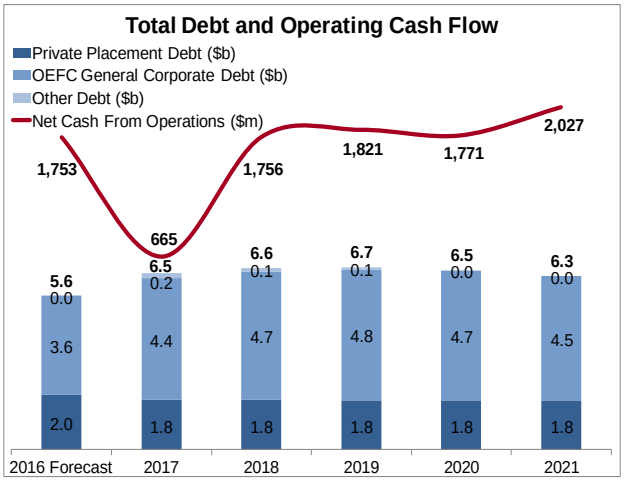
The plan reflects estimated impacts from the 2017 ONFA Reference Plan, assumed to be approved by the Minister of Finance by the end of 2016. The impacts over the planning period include the elimination of ~$180 million per year in OPG's contributions to the ONFA segregated funds, due to lower funding obligations for nuclear decommissioning and waste management. The impacts also include a decrease of ~$1.5 billion in OPG's present value accounting liability for these obligations, at the end of 2016. The main driver of the reduced obligations is lower costs associated with the long-term management of used nuclear fuel as estimated by the Nuclear Waste Management Organization. The lower costs are primarily due to a combination of a more cost effective used fuel disposal container and a delay in the assumed construction of the used fuel deep geologic repository as part of the Adaptive Phase Management plan. OPG's decommissioning and waste management obligations include those for the stations leased to Bruce Power.

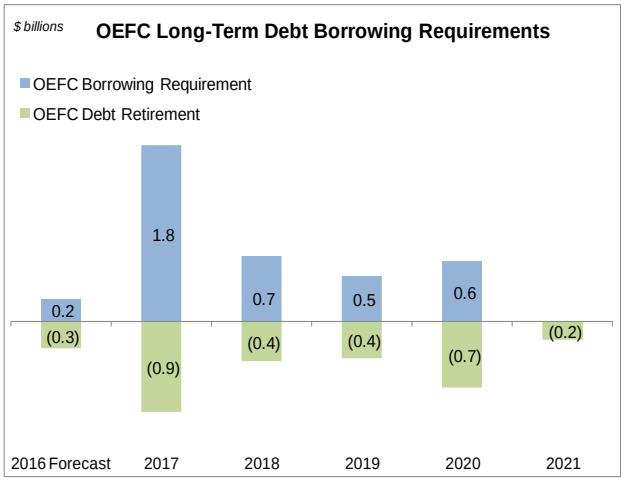
The reduction in segregated fund contributions reflects the expectation that both the Decommissioning Segregated Fund and the Used Fuel Segregated Fund will be fully funded when the new ONFA Reference Plan with lower obligations is approved by the Province. This change improves OPG's operating cash flow but will not impact earnings, as the contributions are not treated as operating expenses. The reduction in the accounting liability lowers future depreciation, accretion and other related expenses; however, the majority of this impact does not affect net income as it will reduce amounts recovered through regulated rates. Upon approval of the new ONFA Reference Plan, OPG expects to file an update to its May 2016 rate application to reflect the lower costs to the benefit of customers.

**Financing and Liquidity**

With the exception of 2017, OPG's operating cash flow outlook is forecast to improve over the planning period, from ~$1.75 billion in 2016 to ~$2 billion in 2021. In 2017, operating cash flow is expected to

decline by over ~$1 billion from 2016 levels, primarily as nuclear production decreases by ~8 TWh, a nuclear rate rider of $10.84/MWh for collection of deferral and variance account balances expires at the end of 2016, and the collection of new regulated rates based on the anticipated timing of the OEB's decision on OPG's rate application does not begin until approximately the fourth quarter of 2017. Assuming that the OEB's decision is issued in the third quarter of 2017 and makes new rates effective January 1, 2017, the full revenue shortfall for the period between January 1, 2017 and the implementation date of the decision would be accrued in net income at the time of the decision, but would be collected over time. Higher operating cash flow starting in 2018 reflects 11% per year increases in nuclear base rates, partly offset by the impact of decreasing nuclear production in 2020 and 2021.



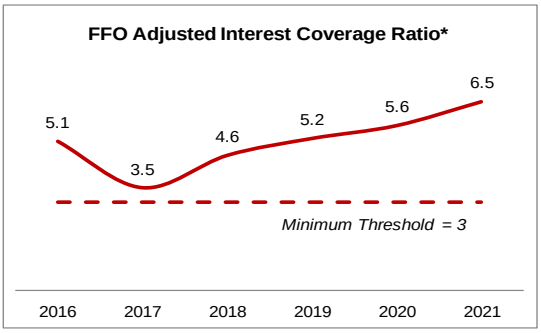




Total debt is forecast to increase from ~$5.6 billion in 2016 to ~$6.7 billion in 2019, as nuclear rate smoothing defers collection of revenue and operating cash flow does not fully fund capital expenditures. Total debt then declines to ~$6.3 billion by 2021 as operating cash flow exceeds capital expenditures. The assumed effective interest rate for new debt is 4.5%, resulting in a weighted average interest rate on OPG's long-term debt of approximately 4.75% over the planning period. The debt ratio ranges from 31% to 37% over the period, which is well below the over 50% level reflected in the OEB deemed capital structure used to set regulated rates.

The cash flow forecast for 2017 includes proceeds from the Shareholder-directed sale of OPG's head office property, an asset of OPG's unregulated business, and the payment of a corresponding dividend to the Province. No other dividends are included during the planning period at this time.

Pending ongoing discussions with the Shareholder regarding OPG's proposed strategy to migrate the capital structure to increase debt and decrease equity, with a view to pursuing a public debt offering strategy in conjunction with a focused growth strategy, the plan assumes that Darlington refurbishment expenditures and other corporate borrowing needs continue to be financed through general-purpose long-term corporate debt sourced through the Ontario Electricity Financial Corporation (OEFC).

At the end of September 2016, OPG's average term to maturity of OEFC debt is less than 6 years. OPG intends to extend this average term to reflect the longer life cycle of its assets; however the OEFC restricts the amount of debt OPG can issue with a term longer than 10 years to 50% of the amount issued at any time. This restriction increases interest rate risk and refinancing risk, as debt will need to be refinanced in the future, at which time the interest rates may be significantly higher than the current historically low rates. OPG believes that, with interest rates at these low levels, it is prudent to take advantage of beneficial market conditions to issue longer term debt to fix future interest costs.



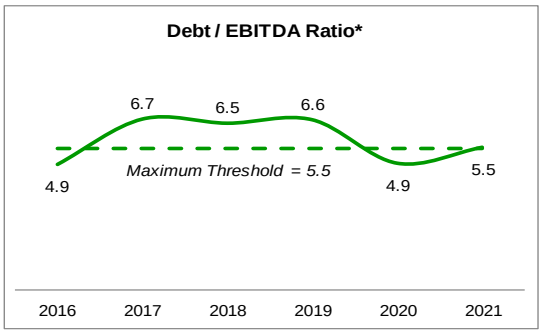

* Calculated using the methodology per OPG's external financial filings

**Credit Metrics**

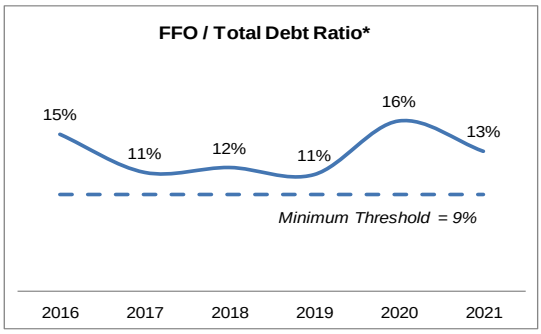
Maintaining an investment grade credit rating is critical to the Company's ability to access cost effective financing. To support this objective, OPG monitors the Funds from Operations (FFO)/Total Debt ratio and the Debt/EBITDA ratio, which are the core measures used in Standard & Poor's credit rating methodology. OPG also monitors the

FFO Adjusted Interest Coverage ratio, which is the Company's main liquidity metric.

The FFO Adjusted Interest Coverage ratio and the FFO/Total Debt ratio are forecast to remain within threshold limits during the 2017-2021 period. The Debt/EBITDA ratio exceeds the threshold limit from 2017 to 2019, as debt levels increase. Compared to 2016, the 2017-2019 ratios are also affected by a lower EBITDA, which reflects lower revenues due to the expiry of 2016 rate riders for the recovery of deferral and variance accounts, the amortization expense for which is not included in the EBITDA calculation, as well as lower hydroelectric production due to outages over the 2017-2019 period. The ratio again approaches the threshold limit in 2021, due to lower EBITDA compared to 2020.




* Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities



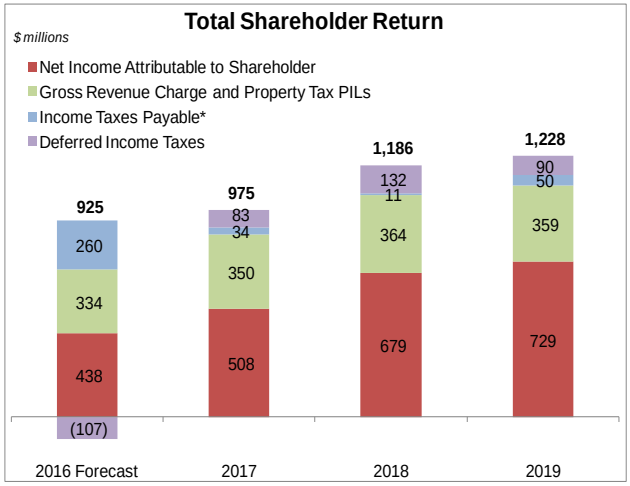

* Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities

Management believes that the forecast credit metrics and operating cash flow, combined with the support for future collection of rate smoothing deferrals under the regulation, should continue to support OPG's current investment grade credit rating. Different regulatory outcomes from those assumed in the plan could result in significantly lower cash flows, increased borrowing and weaker credit metrics, increasing the risk of a credit rating downgrade. In turn, this could increase costs, limit borrowing capacity, and/or necessitate curtailment of project or other expenditures.

### Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric GRC payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute ~$3.4 billion in Total Shareholder Return over the 2017-2019 period.

The 2017 Total Shareholder Return on OPG's fiscal basis is projected at $975 million, an increase over $925 million forecast for 2016. Total Shareholder Return is projected to increase to ~$1.2 billion per year in 2018 and 2019, as net income increases.




* Includes income tax PILs and amounts recoverable from, or payable to ratepayers

## Social Licence

OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous Relations.

### Environment and Climate Change

OPG's virtually carbon free generation has underpinned the decarbonisation of the power sector and can act as a catalyst for reducing carbon emissions from the broader economy. With a generating fleet that is 99% emission free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. OPG's business plan supports Ontario's climate change strategy and technology deployment and electrification objectives, including microgrids, energy storage technology and electric vehicles. In addition to continuing to drive a focus on environmental performance through business plan targets, the decisions to proceed with the Darlington refurbishment and to pursue continued operations at Pickering will contribute to achieving Ontario's climate change objectives by leveraging OPG's lower-priced, carbon-free baseload nuclear power. It is expected that the refurbished Darlington station will

reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million cars per year from Ontario's roads.

Climate change adaption and related safety considerations are a key aspect of OPG's plans for the hydroelectric facilities. These plans consider the impact of water availability, its utilization and the associated environmental and stewardship responsibilities. OPG is also taking steps to better understand the potential changes in water flow conditions that these facilities may experience, including consideration of extreme weather events. This includes development of flood forecasting models in an effort to better predict potential impacts of these changes and to put in place appropriate risk mitigation plans. OPG will continue to operate its hydroelectric facilities by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds while optimizing electricity production.

OPG is in the process of obtaining approvals, establishing processes, and implementing systems for compliance with the requirements of Ontario's new climate change legislation including a cap-and-trade program effective January 1, 2017. Overall, compliance with these requirements is not expected to have a significant financial cost impact on the plan given OPG's virtually emission free generating fleet.

**Public Safety**

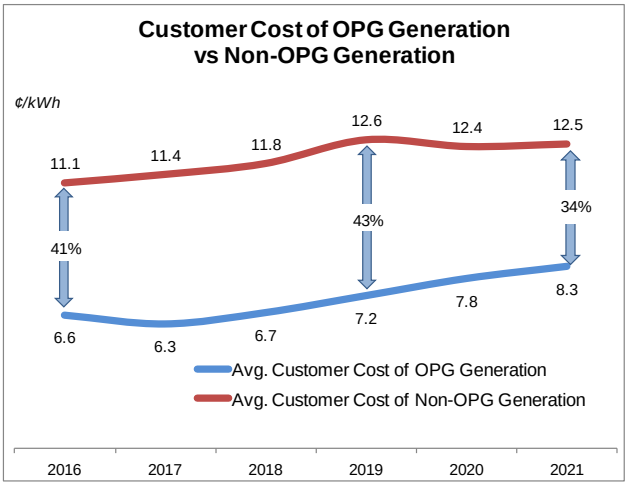
OPG is committed to high standards of workplace and public safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. In particular, OPG will continue to operate with nuclear safety as an overriding priority, by maintaining a strong focus on nuclear safety programs and continuing to invest in nuclear safety systems. In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. OPG also will continue to demonstrate strong industry leadership with its hydroelectric Dam Safety Program, which encompasses public safety and emergency management over the Company's 238 dams and 65 hydroelectric facilities. Many aspects of the program are considered to be international best practice.

**Indigenous Relations**

Throughout the planning period, OPG will remain committed to engaging proactively and building long-term, mutually beneficial working relationships with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing generation-related development partnerships, such as the Peter Sutherland Sr. GS and the Nanticoke solar facility, collaborating on capacity building initiatives and projects, such as the recently completed shoreline restoration projects, and conducting community outreach efforts.

**Moderating Electricity Prices and Contributing to the Economy**

Taking into account the assumed rate increases over the 2017-2021 period from OPG's current rate application, the cost to customers of electricity generated by OPG is expected to remain over ~40% below the average non-OPG cost of electricity in Ontario to 2019 and close to ~35% lower by 2021. The expected average increase from OPG's nuclear and hydroelectric rate application on a typical residential customer's monthly bill over the period to 2021 is estimated to be ~0.7% each year.




OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station. According to The Conference Board of Canada, Ontario's Gross Domestic Product is estimated to increase by a total of ~$90 billion in the period spanning to the end of the post-refurbishment life of the station.

## RECOMMENDATION / RESOLUTION

It is recommended that the Board of Directors approve OPG's 2017-2019 Business Plan including the financial projection for the 2020-2021 period.

**Recommended by:**

[original signed by]
Ken Hartwick
Senior Vice President,
Finance, Strategy, Risk and
Chief Financial Officer

**Approved for submission to the Board of Directors by:**

[original signed by]
Jeff Lyash
President and CEO

This Board memo was reviewed and approved for submission to the Board of Directors by the Audit and Risk Committee at their meeting on November 8, 2016.

## APPENDICES

1. Key Planning Assumptions
2. Key Risks
3. Financial and Headcount Plan Information
4. Nuclear Financial Plan, Operational Targets, and Initiatives
5. Nuclear Strategic Framework
6. Renewable Generation & Power Marketing Financial Plan, Operational Targets, and Initiatives
7. Business and Administrative Services (BAS) Financial Plan, Operational Targets, and Initiatives

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

- Darlington Unit 2 is refurbished from October 2016 to February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in July 2021.
- All six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
- A station-wide Vacuum Building Outage takes place at Pickering in 2021
- The plan reflects currently approved accounting station service lives for Pickering to December 2020, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061. The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.
- The first Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- The site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental expenses are allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities starting in 2018
- The following major projects are carried out at the Sir Adam Beck plants:
    - Sir Adam Beck Pump GS reservoir rehabilitation is completed in the first half of 2017
    - Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz over the 2018-2020 period
    - Sir Adam Beck I GS power canal liner rehabilitation takes place over 2020 and 2021
- Peter Sutherland Sr. GS is in service in 2017 and Lower Mattagami dam safety upgrade in 2019
- The Thunder Bay GS operates until the end of the current biomass energy supply agreement in 2020
- The Nanticoke solar facility is in service in 2019. The former Nanticoke GS is decommissioned, taking into account the impact on the construction and operation of the solar facility.
- Nuclear base rates increase by 11% per year under nuclear rate smoothing, effective January 1, 2017. Effective January 1, 2017, hydroelectric base rates increase by ~1.5% per year, off the existing base rates with some adjustments, under an incentive regulation approach.
- Recoveries for pension and OPEB are limited to cash requirements in the 2017-2021 rate application, pending the outcome of OEB's generic consultation and any other applicable OEB determinations, with the difference between cash and accrual amounts continuing to accumulate in the existing deferral account (for nuclear and hydroelectric operations)
- Carbon pricing in Ontario is based on the Province's cap-and-trade program effective January 1, 2017
- The sale of OPG's head office property, an asset of the unregulated business, is closed in the second quarter of 2017 and a corresponding dividend paid in 2017, as directed by the Shareholder. No other dividends are assumed in the plan at this time.
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. An accounting discount rate of 3.6% is used for valuing pension costs and 3.7% for other post retirement benefit costs.
- The plan reflects the January 1, 2016 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and a subsequent valuation as of January 1, 2019
- Due to inherent uncertainties, inflationary impacts on salary costs are assumed for periods after the expiry of the current collective agreements
- The 2017 ONFA Reference Plan is assumed to be approved by the Province by the end of 2016
- Existing OEFC debt platform continues to be used for long-term corporate debt purposes, pending ongoing discussions with the Province regarding OPG's proposal to move to a public debt platform. The assumed effective interest rate for new debt is 4.5%.
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP for the full planning period

## APPENDIX 2: KEY RISKS

The key risks associated with the 2017-2019 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule;
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance;
- Risk of the Province not concurring with the refurbishment of the subsequent Darlington units;
- Inability to retain and attract effective, knowledgeable and engaged leadership talent during the Darlington refurbishment and continued Pickering operations given an aging workforce and Management group compensation constraints;
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges;
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance;
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures; and
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions.

### Rate Regulation Risks

OEB rulings impacting OPG's rate regulated operations may be unfavourable compared to assumptions in the plan, including the following:

- Inability to receive sufficient assurance from the OEB for future recovery of the pension and OPEB cash-to-accrual deferral account balance projected at ~$480 million by the end of 2016 with further additions totalling ~$150 million over the 2017-2021 period, and associated taxes, which would result in a write-off against net income;
- An OEB-set nuclear rate smoothing trajectory that does not provide sufficient cash flow to fund operations, projects and/or obligations, and/or to maintain the current investment grade credit rating. A credit rating downgrade would increase borrowing costs and could reduce borrowing capacity;
- OEB-approved revenue requirements that do not allow for recovery of the full costs of the regulated operations and/or do not allow the regulated business to earn an appropriate return; and
- An effective date for new regulated rates that is later than the assumed January 1, 2017 date, which would reduce 2017 planned net income by ~$50 to $60 million per month.

### Financial Risks

- Risk of delay in the Province's approval of the 2017 ONFA Reference Plan to 2017, which could result in a reduction in 2017 planned nuclear segregated fund earnings, through a reduction limiting fund asset balance sheet values to the updated, lower ONFA funding obligations. The impact of this reduction is currently reflected in the 2016 forecast net income on the assumption that the new reference plan is approved by the end of 2016.
- Risk of lower than planned returns on segregated nuclear and pension fund assets as a result of various market factors, including equity prices, interest rates, inflation, and commodity prices, which would lower net income and potentially increase future funding requirements compared to the plan;
- Risk of lower discount rates and other differences in assumptions for future pension and OPEB accounting and funding valuations, compared to the plan, including those due to underlying financial market conditions; and
- Risk of adoption of IFRS for financial reporting purposes, either as a result of the expiry of the Ontario Securities Commission exemption allowing OPG to prepare its consolidated financial statements under US GAAP or the Shareholder's requirement to consolidate OPG's results using IFRS. Adoption of IFRS is expected to cause significant net income volatility compared to US GAAP.

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to the Shareholder | 438 | 508 | 679 | 729 | 883 | 1,004 |
| Net Income | 455 | 525 | 695 | 745 | 899 | 1,020 |
| Earnings Before Tax | 608 | 641 | 838 | 885 | 1,216 | 1,262 |
| Return on Equity* *(%)* | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| Nuclear Total Generating Cost per MWh** *($/MWh)* | 63.2 | 75.6 | 74.6 | 74.5 | 77.1 | 77.3 |
| Hydroelectric Total Generating Cost per MWh** *($/MWh)* | 25.1 | 26.4 | 30.1 | 30.3 | 30.0 | 29.0 |
| Enterprise Total Generating Cost per MWh** *($/MWh)* | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |
| FFO / Total Debt Ratio *(%) (Minimum threshold of 9%)* | 15% | 11% | 12% | 11% | 16% | 13% |
| Debt / EBITDA Ratio (times) *(Maximum threshold of 5.5)* | 4.9 | 6.7 | 6.5 | 6.6 | 4.9 | 5.5 |
| FFO Adjusted Interest Coverage Ratio* (times) *(Minimum threshold of 3)* | 5.1 | 3.5 | 4.6 | 5.2 | 5.6 | 6.5 |
| Debt Ratio *(%)* | 34% | 37% | 36% | 35% | 33% | 31% |
| Net Cash from Operations | 1,753 | 665 | 1,756 | 1,821 | 1,771 | 2,027 |
| Cash Balance at Year-End | 275 | 259 | 264 | 246 | 224 | 462 |
| Total Debt at Year-End | 5,608 | 6,458 | 6,630 | 6,662 | 6,549 | 6,336 |
| Total Return to Shareholder*** | 925 | 975 | 1,186 | 1,228 | 1,549 | 1,590 |
| OM&A Expenses from Ongoing Operations | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| Darlington Refurbishment Capital Expenditures | 1,037 | 1,152 | 1,113 | 1,111 | 1,045 | 1,061 |
| Darlington Refurbishment In-Service Additions | 387 | 398 | 2 | - | 4,849 | - |
| Capital Expenditures excluding Darlington Refurbishment | 702 | 626 | 792 | 743 | 617 | 498 |
| In-Service Additions excluding Darlington Refurbishment | 587 | 1,003 | 593 | 1,031 | 558 | 594 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 302 | 425 | 432 | 438 | 494 | 527 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Nuclear TGC/MWh adjusted for lower production due to the Darlington refurbishment outages is: $63.8/MWh in 2017, $63.2/MWh in 2018, $65.8/MWh in 2019, $62.8/MWh in 2020 and $60.4/MWh in 2021.

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

| Total Shareholder Return | Provincial Fiscal Year Basis ending March 31 | | | |
|---|---|---|---|---|
| *$ millions* | 2017 | 2018 | 2019 | 2020 |
| **Net Income Attributable to Shareholder** | **349** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | |
| GRC: Payable to OEFC & Niagara Parks Commission | 321 | 332 | 344 | 343 |
| Property Tax Payable to OEFC | 15 | 18 | 19 | 19 |
| **Total Non Income Tax PILs** | **336** | **350** | **363** | **362** |
| **Income Tax PILs** | **96** | **166** | **135** | **170** |
| **Total Shareholder Return** | **781** | **1,218** | **1,176** | **1,258** |

| Operating Statement - Years Ended December 31 | Forecast | Business Plan | | |
|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 |
| Electricity Generation Revenues | 5,282 | 4,641 | 5,165 | 5,333 |
| Fuel and Gross Revenue Charge | 727 | 675 | 685 | 689 |
| **Generation Sales Gross Margin** | **4,555** | **3,966** | **4,480** | **4,644** |
| Net Trading Margin | 22 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 338 | 298 | 290 | 280 |
| **Total Gross Margin** | 4,916 | 4,282 | 4,788 | 4,943 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,761 | 2,840 | 2,864 | 2,947 |
| Accretion on Nuclear Waste and Other Liabilities | 926 | 969 | 983 | 1,013 |
| Earnings on Nuclear Funds | (755) | (818) | (852) | (886) |
| Depreciation and Amortization | 1,268 | 832 | 876 | 962 |
| Property Taxes | 48 | 47 | 47 | 48 |
| Restructuring | - | 3 | - | - |
| **Total Expenses** | 4,248 | 3,872 | 3,918 | 4,084 |
| **Income before Interest and Other Income** | **668** | **410** | **870** | **858** |
| Net Interest Expense | 125 | 120 | 71 | 14 |
| Other (Income)/Expense* | (65) | (351) | (39) | (40) |
| **Income before Tax** | **608** | **641** | **838** | **885** |
| Income Tax | 153 | 116 | 143 | 140 |
| **Net Income** | **455** | **525** | **695** | **745** |
| **Net Income Attributable to the Shareholder** | **438** | **508** | **679** | **729** |
| Net Income Attributable to Non-Controlling Interests | 16 | 17 | 16 | 16 |

* Includes $28M and $9M in 2016, $28M and $10M in 2017, $26M and $11M in 2018, $27M and $12M in 2019 representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, also includes a pre-tax gain of $296M on the Shareholder-directed sale of OPG's head office property, as well as a pre-tax gain of $15M on the sale of the R.L Hearn GS site, both assets of OPG's unregulated business.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 |
|---|---|---|---|---|
| ***Assets*** | | | | |
| **Current assets** | | | | |
| Cash and cash equivalents | 275 | 259 | 264 | 246 |
| Available-for-sale securities | 233 | 217 | 196 | 177 |
| Short-term investments | 70 | - | - | - |
| Accounts receivable* | 551 | 759 | 562 | 602 |
| Fuel inventory | 308 | 296 | 295 | 231 |
| Materials and supplies | 96 | 96 | 96 | 96 |
| Other current assets | 207 | 116 | 116 | 116 |
| | 1,740 | 1,743 | 1,529 | 1,468 |
| **Property, plant and equipment and intangible assets** | | | | |
| Fixed and intangible assets (net)** | 20,200 | 21,273 | 22,365 | 23,450 |
| **Other assets** | | | | |
| Nuclear fixed asset removal and nuclear waste management funds | 15,950 | 16,613 | 17,309 | 17,981 |
| Long-term materials and supplies | 340 | 339 | 332 | 322 |
| Regulatory assets (net) | 6,412 | 7,075 | 7,532 | 7,637 |
| Investments subject to significant influence | 321 | 308 | 299 | 288 |
| Other long-term assets | 63 | 63 | 63 | 63 |
| | 23,086 | 24,398 | 25,534 | 26,292 |
| ***Total Assets*** | **45,026** | **47,414** | **49,428** | **51,211** |
| ***Liabilities*** | | | | |
| **Current liabilities** | | | | |
| Short-term notes payable | 2 | 205 | 125 | 75 |
| Accounts payable and accrued charges | 1,153 | 1,585 | 1,731 | 1,870 |
| Deferred revenue due within one year | 12 | 12 | - | - |
| Current income taxes payable | 121 | 49 | 91 | 128 |
| Long-term debt due within one year | 1,103 | 398 | 368 | 663 |
| | 2,391 | 2,249 | 2,316 | 2,736 |
| **Long-term debt** | 4,503 | 5,855 | 6,137 | 5,924 |
| **Other liabilities** | | | | |
| Fixed asset removal and nuclear waste management liabilities** | 19,496 | 20,177 | 20,863 | 21,592 |
| Pension liabilities (non-current) | 3,933 | 3,930 | 3,936 | 3,879 |
| Other post-employment benefit liabilities (non-current) | 3,035 | 3,128 | 3,223 | 3,319 |
| Long-term accounts payable and accrued charges | 185 | 168 | 173 | 174 |
| Deferred revenue | 298 | 351 | 419 | 409 |
| Deferred income taxes | 751 | 834 | 966 | 1,054 |
| | 27,698 | 28,590 | 29,579 | 30,428 |
| ***Equity*** | | | | |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 5,536 | 5,822 | 6,501 | 7,230 |
| Accumulated other comprehensive loss | (366) | (365) | (367) | (369) |
| Equity attributable to non-controlling interests | 137 | 138 | 136 | 135 |
| | 10,434 | 10,721 | 11,397 | 12,123 |
| ***Total Liabilities and Equity*** | **45,026** | **47,414** | **49,428** | **51,211** |

* As at December 31, 2017, includes accrued revenues for new regulated rates for the period from January 1, 2017 to the implementation date of the OEB's decision, which is assumed to be received in the third quarter of 2017. The accrued balance is assumed to be fully collected by the end of 2018.

** As at December 31, 2016, reflects an adjustment that reduces the nuclear decommissioning and waste management liabilities based on cost estimates from the 2017 ONFA Reference Plan update process.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 | Projection<br>2020 | <br>2021 |
|---|---|---|---|---|---|---|
| Nuclear Operations* | 1,601 | 1,725 | 1,735 | 1,786 | 1,777 | 1,689 |
| Renewable Generation & Power Marketing | 370 | 417 | 432 | 433 | 448 | 433 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **1,973** | **2,144** | **2,169** | **2,222** | **2,228** | **2,125** |
| Business and Administrative Services<br>(Chief Information Officer, Real Estate, Supply Chain) | 298 | 299 | 295 | 300 | 305 | 309 |
| Finance (excl. Insurance)<br>(Finance, Risk & Assurance, Corp. Bus. Development) | 82 | 84 | 81 | 80 | 80 | 81 |
| Insurance | 31 | 42 | 45 | 48 | 52 | 53 |
| People/Culture & Communications | 135 | 149 | 148 | 150 | 152 | 151 |
| Legal/Ethics & Compliance<br>(Law, Regulatory Affairs, Environment) | 32 | 36 | 32 | 32 | 33 | 35 |
| Corporate Office | 5 | 7 | 7 | 8 | 8 | 8 |
| **Total Support Services** | **582** | **616** | **608** | **618** | **629** | **637** |
| **Total Business Unit Expenditures** | **2,555** | **2,760** | **2,776** | **2,840** | **2,856** | **2,762** |
| Centrally Held Pension and OPEB | 277 | 89 | 60 | 42 | 37 | 37 |
| Other (incl. Cost of Goods Sold) | 77 | 67 | 88 | 81 | 90 | 92 |
| **Total Ongoing Operations** | **2,909** | **2,916** | **2,924** | **2,964** | **2,983** | **2,891** |
| OEB Variance and Deferral Account Offsets | (129) | (103) | (62) | (12) | (7) | (6) |
| Darlington Refurbishment Project | 3 | 49 | 16 | 7 | 52 | 26 |
| Nuclear New Build | 1 | 2 | 7 | 10 | 11 | 11 |
| **Total OM&A Expenses** | **2,785** | **2,863** | **2,886** | **2,968** | **3,040** | **2,922** |

* Total Pickering extended operations enabling costs are: $15M in 2016, $26M in 2017, $55M in 2018, $107M in 2019 and $104M in 2020.

| Regular Headcount by Business Unit | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Nuclear Operations | 5,552 | 5,760 | 5,755 | 5,678 | 5,571 | 5,496 |
| Renewable Generation & Power Marketing | 1,524 | 1,540 | 1,517 | 1,508 | 1,484 | 1,445 |
| Other Unregulated Operations | 2 | 5 | 5 | 5 | 5 | 5 |
| **Total Operations** | **7,078** | **7,305** | **7,277** | **7,191** | **7,060** | **6,946** |
| Business and Administrative Services (Chief Information Officer, Real Estate, Supply Chain) | 829 | 864 | 863 | 862 | 849 | 849 |
| Finance (Finance, Risk & Assurance, Corp. Bus. Development) | 350 | 351 | 343 | 337 | 332 | 332 |
| People/Culture & Communications | 647 | 681 | 674 | 678 | 673 | 665 |
| Legal/Ethics & Compliance (Law, Regulatory Affairs, Environment) | 96 | 99 | 98 | 98 | 98 | 98 |
| Corporate Office | 9 | 12 | 12 | 12 | 12 | 12 |
| **Total Support Services** | **1,931** | **2,007** | **1,990** | **1,987** | **1,964** | **1,956** |
| **Total Ongoing Operations** | **9,009** | **9,312** | **9,267** | **9,178** | **9,024** | **8,902** |
| Darlington Refurbishment Project | 458 | 631 | 642 | 626 | 610 | 642 |
| **Total Regular Headcount** | **9,467** | **9,943** | **9,909** | **9,804** | **9,634** | **9,544** |

| Capital Expenditures<br>*(in millions of dollars)* | Forecast<br>2016 | Business Plan<br>2017 | <br>2018 | <br>2019 | Projection<br>2020 | <br>2021 |
|---|---|---|---|---|---|---|
| **Sustaining** | | | | | | |
| **Nuclear** | 291 | 322 | 319 | 299 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | | |
| Sir Adam Beck 1 Canal Liner Rehabilitation | - | - | 1 | 1 | 62 | 62 |
| Sir Adam Beck Pump GS Reservoir Rehabilitation | 40 | 7 | - | - | - | - |
| Other Projects | 109 | 125 | 111 | 120 | 153 | 133 |
| **Total Regulated Hydroelectric** | 149 | 132 | 112 | 122 | 215 | 195 |
| **Contracted Generation Portfolio** | | | | | | |
| Lower Mattagami Dam Safety Upgrade (formerly Adam Creek Spillway Expansion) | - | 5 | 145 | 145 | 5 | - |
| Other Projects | 39 | 32 | 32 | 24 | 11 | 6 |
| **Total Contracted Generation Portfolio** | 39 | 37 | 177 | 169 | 16 | 6 |
| **Support Services** | 59 | 49 | 38 | 38 | 35 | 35 |
| **Total Sustaining Capital** | **537** | **540** | **646** | **628** | **555** | **480** |
| **Generation Development Projects*** | | | | | | |
| **Hydroelectric Development** | | | | | | |
| Peter Sutherland Sr. GS** | 145 | 41 | 5 | 0 | - | - |
| Sir Adam Beck Units 1 & 2 Conversion | - | 2 | 17 | 43 | 27 | - |
| Lower Mattagami River Project** | 16 | - | - | - | - | - |
| Ranney Falls GS Expansion | 2 | 35 | 18 | 8 | - | - |
| Coniston GS Redevelopment | - | - | 6 | 28 | 14 | 7 |
| Calabogie GS Redevelopment | - | 3 | 4 | 34 | 20 | 11 |
| Other | 1 | 0 | 1 | 2 | 2 | - |
| **Total Hydroelectric Development** | 164 | 81 | 51 | 115 | 63 | 18 |
| **Darlington Refurbishment Project***** | 1,037 | 1,152 | 1,113 | 1,111 | 1,045 | 1,061 |
| **Nanticoke Solar Project** | 1 | 5 | 95 | - | - | - |
| **Total Generation Development Capital** | **1,202** | **1,239** | **1,259** | **1,226** | **1,107** | **1,079** |
| **Total Capital Expenditures** | **1,739** | **1,778** | **1,905** | **1,854** | **1,662** | **1,559** |

* While in definition phase, projects are budgeted by Corporate Business Development and, while in execution phase, projects are budgeted by RG&PM

** Includes expenditures budgeted by RG&PM and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| **Provision Expenditures** *(in millions of dollars)* | Forecast 2016 | Business Plan 2017 | 2018 | 2019 | Projection 2020 | 2021 |
|---|---|---|---|---|---|---|
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | | |
| Nuclear Operations* | 272 | 358 | 377 | 418 | 471 | 511 |
| Support Services | 15 | 16 | 16 | 13 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **287** | **375** | **392** | **431** | **485** | **525** |
| Nanticoke GS Decommissioning | | 46 | 32 | 6 | 1 | 1 |
| Other | 16 | 4 | 8 | 1 | 9 | 1 |
| **Total Thermal Decommissioning Expenditures** | **16** | **50** | **40** | **7** | **10** | **2** |
| **Total Provision Expenditures** | **302** | **425** | **432** | **438** | **494** | **527** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| **Financing and Liquidity Outlook - Years Ended Dec 31** *(in millions of dollars)* | | Forecast 2016 | Business Plan 2017 | 2018 | 2019 | Projection 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| ***Opening Cash Balance*** | | **464** | **275** | **259** | **264** | **246** | **224** |
| **Net Operating Cash Inflows before the following:** | | **2,739** | **1,531** | **2,648** | **2,756** | **2,715** | **2,953** |
| Interest Paid | | (266) | (286) | (288) | (295) | (298) | (289) |
| Nuclear Funds Contribution | | (150) | - | - | - | - | - |
| Pension Fund Contribution | | (253) | (248) | (251) | (299) | (305) | (308) |
| OPEB Payments | | (120) | (113) | (118) | (123) | (128) | (133) |
| Internally Funded Nuclear Provision Expenditures | | (196) | (220) | (236) | (217) | (213) | (195) |
| **Net Cash from Operations** | | **1,753** | **665** | **1,756** | **1,821** | **1,771** | **2,027** |
| **Investing Activities** | | | | | | | |
| Sustaining Capital Expenditures | | (537) | (540) | (646) | (628) | (555) | (480) |
| Darlington Refurbishment | | (1,037) | (1,152) | (1,113) | (1,111) | (1,045) | (1,061) |
| Peter Sutherland Sr. GS (PS) | | (145) | (41) | (5) | (0) | - | - |
| Nanticoke Solar | | (1) | (5) | (95) | - | - | - |
| Other Generation Development | | (19) | (40) | (46) | (115) | (63) | (18) |
| **Cash Outflow for Capital Investments** | | **(1,739)** | **(1,778)** | **(1,905)** | **(1,854)** | **(1,662)** | **(1,559)** |
| (Investment in) Proceeds from Deposit Note (PS) | | 110 | 70 | - | - | - | - |
| Pre-tax Proceeds from Sale of OPG Head Office | | - | 400 | - | - | - | - |
| Pre-tax Proceeds from Sale of R.L. Hearn GS Site | | | 16 | | | | |
| Investment in Hydro One Shares | | (213) | - | - | - | - | - |
| Other | | (4) | - | - | - | - | - |
| **Net Cash Outflow for Investing Activities** | | **(1,846)** | **(1,292)** | **(1,905)** | **(1,854)** | **(1,662)** | **(1,559)** |
| **Financing Activities** | | | | | | | |
| General Corporate (OEFC) | - *Debt Issuance/Refinancing* | 220 | 1,750 | 650 | 450 | 600 | - |
| | - *Debt Retirement* | (270) | (900) | (395) | (365) | (660) | (185) |
| Project Financing (Private Placement) | - *Debt Issuance/Refinancing* | 200 | - | - | - | - | 225 |
| | - *Debt Retirement* | (3) | (203) | (3) | (3) | (3) | (228) |
| Short-Term Notes | - *Net Issuance (Repayment)* | (223) | 203 | (80) | (50) | (50) | (25) |
| Dividends Paid | | - | (223) | - | - | - | - |
| Distribution Paid to Non-Controlling Interests | | (19) | (16) | (17) | (17) | (18) | (18) |
| **Net Cash from Financing Activities** | | **(95)** | **612** | **155** | **15** | **(131)** | **(231)** |
| **Net Cash (Outflow) Inflow for Period** | | **(189)** | **(16)** | **5** | **(18)** | **(22)** | **238** |
| ***Ending Cash Balance*** | | ***275*** | ***259*** | ***264*** | ***246*** | ***224*** | ***462*** |
| ***Total Debt at Year-End*** | | ***5,608*** | ***6,458*** | ***6,630*** | ***6,662*** | ***6,549*** | ***6,336*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | | |
| Base* | 1,172 | 1,196 | 1,215 | 1,254 | 1,263 | 1,281 |
| Outage Incremental | 319 | 392 | 373 | 343 | 328 | 322 |
| Project Portfolio | 94 | 111 | 91 | 82 | 82 | 87 |
| Pickering Continued Operations Enabling Costs | 15 | 26 | 55 | 107 | 104 | - |
| Darlington Refurbishment Project | 3 | 49 | 16 | 7 | 52 | 26 |
| Nuclear New Build | 1 | 2 | 7 | 10 | 11 | 11 |
| **Total Nuclear OM&A** | **1,605** | **1,776** | **1,758** | **1,803** | **1,841** | **1,727** |
| **Capital** | | | | | | |
| Project Portfolio (including Spares and Minor Fixed Assets)** | 291 | 322 | 319 | 299 | 289 | 244 |
| Darlington Refurbishment Project (excl. Support Services) | 1,008 | 1,119 | 1,084 | 1,082 | 1,019 | 1,035 |
| **Total Nuclear Capital** | **1,299** | **1,441** | **1,403** | **1,381** | **1,308** | **1,279** |
| **Provision Expenditures** | | | | | | |
| ONFA Funded | 85 | 150 | 147 | 206 | 264 | 325 |
| Internally Funded - Base | 101 | 115 | 115 | 122 | 125 | 127 |
| Internally Funded - Projects | 54 | 49 | 70 | 45 | 45 | 40 |
| Internally Funded - Darlington Refurbishment Waste Containers | 31 | 44 | 45 | 45 | 38 | 19 |
| **Total Nuclear Provision Expenditures** | **272** | **358** | **377** | **418** | **471** | **511** |
| **Fuel Expense** (Pickering and Darlington) | **263** | **223** | **220** | **228** | **217** | **198** |

* Includes an estimated $4M to $5M per year for work in support of the RG&PM business unit

** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2017-2019 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station and continuing work on fuel channel inspections at the Pickering station.

| | | | Pickering | | | | | Darlington[1] | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | 2016 Target | 2016 Forecast | 2017 Target | 2018 Target | 2019 Target | 2016 Target | 2016 Forecast | 2017 Target | 2018 Target | 2019 Target |
| All Injury Rate[2] (#/200k hrs worked) | N/A | 0.69 | 0.24 | 0.49 | 0.24 | 0.24 | 0.24 | 0.24 | 0.23 | 0.24 | 0.24 | 0.24 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 38.17 | 111.50 | 104.50 | 126.90 | 137.30 | 153.30 | 65.00 | 80.90 | 111.90 | 82.70 | 78.40 |
| Unit Capability Factor (%) | 92.0 | 91.3 | 77.6 | 75.3 | 71.5 | 72.0 | 72.6 | 91.1 | 90.0 | 85.1 | 86.0 | 87.8 |
| Forced Loss Rate (%) | 1.00 | 0.38 | 5.00 | 4.37 | 5.00 | 5.00 | 5.00 | 1.00 | 1.93 | 1.00 | 1.00 | 1.00 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 7 | 55 | 80 | 28 | 28 | 28 | 20 | 20 | 15 | 10 | 7 |
| WANO NPI (Index) | N/A | 93.5 | 72.3 | 75.6 | 69.7 | 67.2 | 65.9 | 87.3 | 85.5 | 83.1 | 90.7 | 91.0 |
| Human Performance Error Rate | N/A | 0.0010 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0030 | 0.0053 | 0.0020 | 0.0020 | 0.0020 |
| Total Generating Cost per MWh[3] | N/A | $38.93 | $71.09 | $72.46 | $78.83 | $80.09 | $81.49 | $47.35 | $46.46 | $49.75 | $49.54 | $52.33 |

[1] Darlington targets reflect the impact of the Unit 2 Refurbishment starting in October of 2016, where applicable.

[2] Also applies to Darlington Refurbishment Project and Contractors.

[3] Metrics exclude centrally-held Pension and OPEB costs and asset service fees. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized after 2016 for generation forgone during the Unit 2 refurbishment.

## Initiatives

The following initiatives represent the focus areas of the Nuclear business unit aimed at closing performance gaps in order to achieve targeted results:

- **Outage Execution:** This initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage day targets. Areas for improvement include: outage schedule and resource planning quality; implementation of a long-term purchased services agreement to optimize contracted work and improve quality of supplemental staff execution; inspection and maintenance execution improvements; Life Cycle Management Plan development improvements; and studying the option of moving Pickering to a 30-month outage cycle.
- **Workforce Planning & Resourcing Initiative:** This initiative focuses on implementing the resourcing strategy to support the safe operation of the plants and successful completion of the Darlington refurbishment, while minimizing disruption and costs associated with the Pickering end of commercial operations. A dedicated team provides oversight on the resourcing strategies and resourcing approval process.
- **Equipment Reliability:** This initiative aims to improve equipment reliability, improve effectiveness of the maintenance program and reduce equipment failures to meet forced loss rate targets.
- **Project Excellence Initiative:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Parts Improvement Sustainment:** This initiative aims to sustain and continuously improve on the results of the 19 completed sub-initiatives of the overall Parts Improvement Project. The focus of the Parts Improvement Project has been on obtaining the right parts on time, reducing churn in the work management system, and ultimately improving equipment reliability through the completion of the 19 cross-functional sub-initiatives across the Engineering, Supply Chain, Fleet Operations & Maintenance, and Work Management functions.
- **Human Performance:** This initiative focuses on: 1) Behaviours associated with procedural use and adherence; 2) Leadership accountability whereby leaders understand and model the behaviours expected from all staff; and 3) Supervisor effectiveness whereby supervisors set and communicate clear expectations to positively influence behaviours.

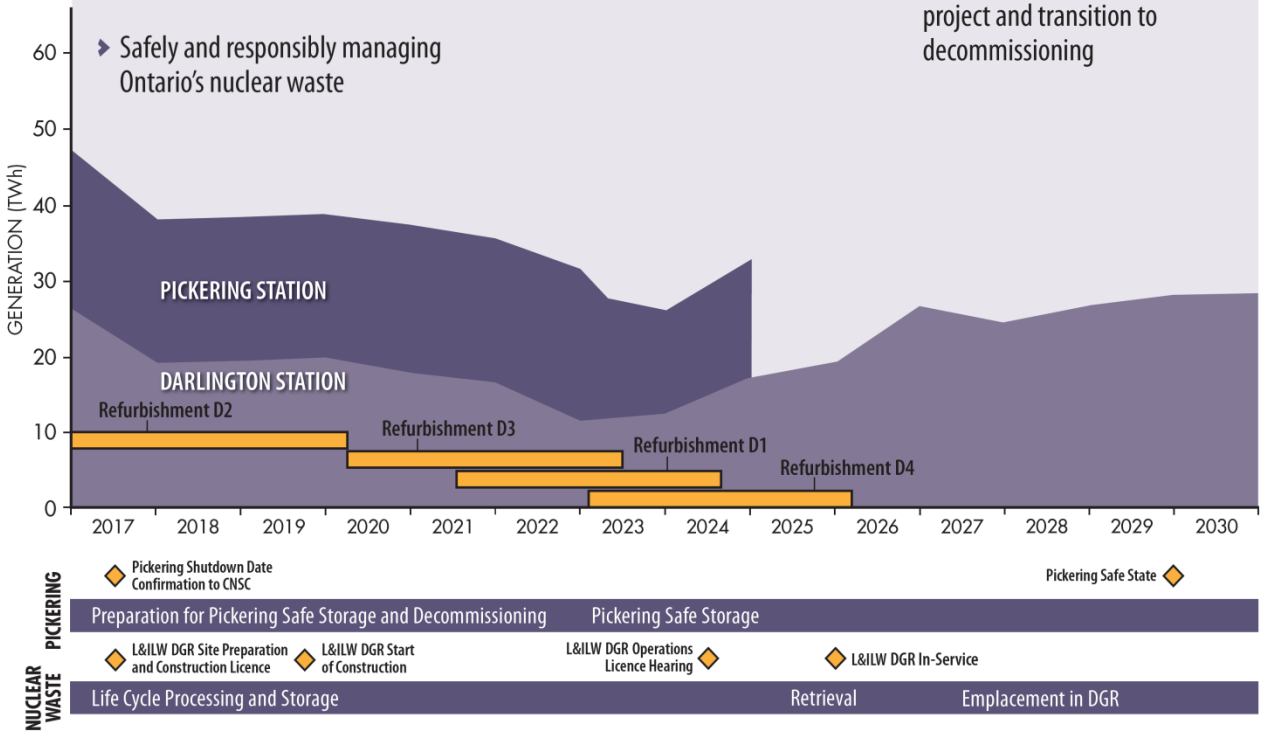
## APPENDIX 5: NUCLEAR STRATEGIC FRAMEWORK

# Nuclear Strategic Framework

## Nuclear Cornerstones of Excellence

• Safety • Reliability • Value for Money • Human Performance

- Extending the life of Pickering station to 2024
- Achieving the cost and schedule commitments for the Darlington Refurbishment Project
- Safely and responsibly managing Ontario's nuclear waste
- Establish an organization that positions Darlington to achieve Top Quartile operational and financial performance
- Execute Pickering SAFSTOR project and transition to decommissioning




## Key Strategic Goals

2017–2019

### OPERATIONAL EXCELLENCE

- Protecting the health and safety of workers, public, environment, and plant.
- Establishing an Equipment Reliability Centre of Excellence to support sustainable reliability of our Nuclear stations.

### PROJECT EXCELLENCE

- Integrating and executing the Darlington Unit 2 Refurbishment on schedule and budget.
- Improving project outcomes across the enterprise through the Project Management Centre of Excellence.

### FINANCIAL STRENGTH

- Focusing on outage performance to meet our generation commitments.
- Optimizing inventory levels while ensuring availability of critical parts.
- Completing assessments to enable extending Pickering operations to 2024.

### SOCIAL LICENCE

- Complying with all applicable laws, codes, and regulations.
- Ensuring safety of the public and environment and reducing tritium emissions as low as reasonably achievable.
- Strong community and stakeholder relations.

## APPENDIX 6: RENEWABLE GENERATION & POWER MARKETING FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | | |
| Regulated Hydroelectric | 192 | 199 | 193 | 194 | 205 | 206 |
| Contracted Generation Portfolio | 99 | 112 | 112 | 114 | 104 | 105 |
| Other* (Including Power Marketing) | 25 | 22 | 16 | 18 | 18 | 18 |
| **Total Base OM&A** | **316** | **333** | **321** | **326** | **327** | **329** |
| Regulated Hydroelectric | 44 | 71 | 95 | 96 | 107 | 98 |
| Contracted Generation Portfolio | 11 | 13 | 16 | 11 | 14 | 6 |
| **Total Project OM&A** | **55** | **84** | **111** | **107** | **121** | **104** |
| Regulated Hydroelectric | 236 | 270 | 287 | 290 | 312 | 303 |
| Contracted Generation Portfolio | 110 | 125 | 129 | 125 | 118 | 111 |
| Other* (Including Power Marketing) | 25 | 22 | 16 | 18 | 18 | 18 |
| **Total RG&PM OM&A** | **370** | **417** | **432** | **433** | **448** | **433** |
| **Capital** | | | | | | |
| **Sustaining** | | | | | | |
| Regulated Hydroelectric | | | | | | |
| Sir Adam Beck Pump GS Reservoir Rehabilitation | 40 | 7 | - | - | - | - |
| Sir Adam Beck I GS Canal Liner Rehabilitation | - | | 1 | 1 | 62 | 62 |
| Other Sustaining Projects | 109 | 125 | 111 | 120 | 153 | 133 |
| **Total Regulated Hydroelectric** | **149** | **132** | **112** | **122** | **215** | **195** |
| Contracted Generation Portfolio | | | | | | |
| Lower Mattagami Dam Safety (formerly Adam Creek Spillway) | - | 5 | 145 | 145 | 5 | - |
| Other Sustaining Projects | 39 | 32 | 32 | 24 | 11 | 6 |
| **Total Contracted Generation Portfolio** | **39** | **37** | **177** | **169** | **16** | **6** |
| **Total Sustaining Capital** | **188** | **169** | **289** | **291** | **231** | **202** |
| **Development Capital** | | | | | | |
| Peter Sutherland Sr. GS (excl. Support Services) | 144 | 41 | 5 | - | - | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 2 | 17 | 43 | 27 | - |
| Lower Mattagami River Project (excl. Support Services) | 16 | - | - | - | - | - |
| Ranney Falls GS Expansion | - | 33 | 18 | 8 | - | - |
| Nanticoke Solar Project | - | 4 | 95 | - | - | - |
| **Total Development Capital** | **160** | **79** | **135** | **50** | **27** | **-** |
| **Total RG&PM Capital** | **348** | **248** | **424** | **341** | **258** | **202** |
| **Thermal Decommissioning Provision Expenditures** | **16** | **50** | **40** | **7** | **10** | **2** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel** | **386** | **386** | **404** | **393** | **381** | **380** |
| Regulated Hydroelectric (net of SBG losses)** | 322 | 331 | 344 | 338 | 327 | 321 |
| Contracted Generation Portfolio | 62 | 53 | 60 | 54 | 54 | 58 |
| Other | 1 | 2 | 0 | 0 | 0 | 0 |

* Includes $8M to $10M per year for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $324M in 2016, $348M in 2017, $357M in 2018, $350M in 2019, $331M in 2020, and $324M in 2021.

## Operational Targets

The key 2017-2019 RG&PM targets designed to drive continuous performance are set out below.

| | Forecast | Business Plan | | |
|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 |
| **All Injury Rate** *(#/200k hrs worked)* | 2.06 | 0.90 | 0.65 | 0.40 |
| **Environment** | | | | |
| Significant Environmental Events (incl. Category A and B Spills) | - | - | - | - |
| Category C Spills | 7 | 9 | 9 | 9 |
| Environmental Infractions | 7 | 8 | 8 | 8 |
| **Capacity** *(MW)* | **9,898** | **9,920** | **9,952** | **10,076** |
| Regulated Hydroelectric | *6,421* | *6,433* | *6,433* | *6,509* |
| Contracted Generation Portfolio (Hydro, Thermal and Solar) | *3,475* | *3,485* | *3,517* | *3,565* |
| Wind (No Contract) | *2* | *2* | *2* | *2* |
| **Hydroelectric Availability** *(%)* | **88.0** | **86.6** | **89.7** | **88.6** |
| Regulated Hydroelectric | *89.1* | *87.3* | *90.0* | *90.7* |
| Contracted Generation Portfolio Hydroelectric | *80.6* | *82.6* | *87.8* | *75.3* |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **2.3** | **1.9** | **1.7** | **1.6** |
| Regulated Hydroelectric | *1.9* | *1.7* | *1.7* | *1.7* |
| Contracted Generation Portfolio Hydroelectric | *5.7* | *3.4* | *2.1* | *1.5* |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | **2.3** | **5.1** | **5.1** | **5.1** |
| **Total Hydroelectric Generating Cost per MWh*** *($/MWh)* | **25.1** | **26.4** | **30.1** | **30.3** |

* Calculated assuming no production is foregone due to SBG losses

## Initiatives

The RG&PM business unit continues to focus on performance excellence, while continuing to drive for efficiency improvements through the following strategic initiatives:

- **Safety:** This initiative will focus on driving improvements in medical treatment injuries through stringent All Injury Rate targets.
- **Workforce Planning and Resourcing Efficiency:** This initiative will focus on resource planning with an emphasis on filling required positions. RG&PM will continue to review positions as they become vacant and challenge whether they are required. Attrition in engineering is being addressed through the re-introduction of the graduate engineer training program and the hiring of additional temporary senior engineers, to address shortfalls in the short term.
- **Environment:** This initiative aims to continue good environmental performance through programs such as the Management Self-Assessment on Drainage Surveys and support of the corporate environmental management system.
- **Project Excellence:** This initiative supports the corporate-wide initiative focused on implementing a standard scalable project delivery model throughout OPG via the established Project Management Centre of Excellence, in order to increase project predictability and successful project outcomes.
- **Operational Excellence:** This initiative focuses on sustaining hydroelectric availability and the thermal Equivalent Forced Outage Rate (operating) across the business plan period, as per targets and contractual limits, to ensure unit availability during the Darlington refurbishment.
- **Building Leadership Capability:** This initiative focuses on building strategic leadership capability, continuous improvement in succession planning, engagement in the company-wide leadership development program, mentoring of high potential individuals, and continuing to strengthen and develop partnerships with host communities and Indigenous communities.
- **Productivity Improvements:** This initiative focuses on continued review of opportunities for efficiency gains from strategic initiatives, optimizing the productivity of maintenance staff, and focusing on the Attendance Support Program.
- **Regionalization:** This initiative will continue to explore further efficiencies through regionalization.

## APPENDIX 7: BUSINESS AND ADMINISTRATIVE SERVICES FINANCIAL PLAN, OPERATIONAL TARGETS, AND INITIATIVES

### Financial Plan

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| *(in millions of dollars)* | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| **OM&A** | | | | | | |
| Chief Information Officer | 118 | 120 | 119 | 121 | 122 | 121 |
| Real Estate | 96 | 99 | 99 | 101 | 102 | 107 |
| Supply Chain | 53 | 56 | 56 | 57 | 58 | 60 |
| SVP Office | 1 | 1 | 1 | 1 | 1 | 1 |
| **Base OM&A** | **267** | **277** | **275** | **280** | **283** | **289** |
| Chief Information Officer | 30 | 16 | 15 | 14 | 15 | 14 |
| Real Estate | 2 | 5 | 5 | 5 | 6 | 5 |
| **Project OM&A** | **32** | **22** | **20** | **19** | **21** | **19** |
| **Total BAS OM&A** | **298** | **299** | **295** | **300** | **305** | **309** |
| **Capital** | | | | | | |
| Chief Information Officer | 41 | 30 | 26 | 26 | 26 | 26 |
| Real Estate | 18 | 18 | 11 | 12 | 8 | 8 |
| Darlington Refurbishment Project | 20 | 22 | 19 | 18 | 17 | 18 |
| **Total BAS Capital** | **79** | **70** | **56** | **56** | **51** | **52** |
| **Nuclear Waste Provision Expenditures** | **3** | **5** | **5** | **5** | **6** | **6** |
| **Non-Electricity Generation Gross Margin** | | | | | | |
| Non-Electricity Generation Revenue | (87) | (57) | (52) | (43) | (40) | (44) |
| Cost of Goods Sold | 19 | 11 | 9 | 9 | 9 | 9 |
| **Total BAS Non-Electricity Generation Gross Margin** | **(68)** | **(46)** | **(43)** | **(34)** | **(31)** | **(35)** |

## Operational Targets

Business and Administrative Services (BAS) comprises the Company's centralized Supply Chain, Chief Information Office, and Real Estate Services functions. The key 2017-2019 targets for BAS include the following:

| | Forecast | Business Plan | | |
|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 |
| **Employee Safety** | | | | |
| All Injury Rate *(#/200k hrs worked)* | < 0.38 | < 0.35 | < 0.35 | < 0.35 |
| Lost Time Injuries | 0 | 0 | 0 | 0 |
| Total Sick Days per Employee Annualized *(days)* | 13.5 | 12.4 | 11.9 | 11.4 |
| **Environment** | | | | |
| Category C Spills | 1 | 1 | 1 | 1 |
| Environmental Infractions | 3 | 3 | 2 | 2 |
| Waste Diversion Target *(%)* | ≥ 80 | ≥ 80 | ≥ 80 | ≥ 80 |
| **Supply Chain** | | | | |
| Unplanned Nuclear Generation Loss Due to Vendor Quality *(days)* | 14.0 | 12.5 | 12.0 | 12.0 |
| Scope Removal due to Unavailable Parts - Nuclear *(%)* | DN=3.0<br>PN=1.8 | 10% of outage scope variance target | | |
| Stock-out Nuclear Materials (Critical 1 & 2 Parts) *(%)* | 1.8 | 1.3 | 1.0 | 1.0 |
| Strategic Sourcing (value improvement on addressable spend) *($m)* | 52.0 | 12.0 | 11.0 | 7.0 |
| Supply Chain Achievement of Projects Business Unit Milestones *(%)* | 100 | 100 | 100 | 100 |
| **Information Technology *(%)*** | | | | |
| Critical IT System Availability | 99.98 | 99.98 | 99.98 | 99.98 |
| Cyber Security Capability Health *(% Adherence to Plan)* | N/A | 98 | 98 | 98 |
| IT Projects Benefits Realization | 98 | 98 | 98 | 98 |
| IT Execution Phase Project Adherence (Portfolio) | 95 | 95 | 95 | 95 |
| **Real Estate** | | | | |
| Cost Performance Index LTD Active Projects | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 |
| Schedule Performance Index LTD Active Projects | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 | ≥ 0.95 |

## Initiatives

Key initiatives of BAS focus on delivering cost effective, value added services in support of generation business unit operations and projects, while continuing to improve efficiency. The initiatives include:

- **Strategic Sourcing**: Supply Chain will maximize OPG spend leverage through a re-compete sourcing strategy and enhanced spend category management to achieve a targeted $30 million value improvement over the business planning period.
- **Project and Contract Management Excellence**: Supply Chain, in collaboration with operating business units, will establish and execute an enterprise-wide model for project and contract management, leveraging industry best practices. This will include establishing a Centre of Excellence to provide leadership and oversight for governance, reporting, systems and tools, and training and development.
- **Supplier Quality and Counterfeit, Fraudulent and Sub-Standard Parts**: While Supply Chain has established effective programs for managing these risks, continuous improvement opportunities will continue to be identified through self-evaluation, benchmarking and third party review. In addition, Supply Chain will expand supplier quality programs to mitigate risk exposure from counterfeit, fraudulent and suspect items across second and third tier sub-suppliers by the fourth quarter of 2018.
- **IT Innovation Strategies and Technology Investments:** Chief Information Office will continue to leverage new IT technologies and automate business processes to deliver operational productivity and cost efficiency improvements.
- **Information Management Optimization Strategy:** Chief Information Office will advance the use of electronic records to transition to a common records and document management system to reduce costs and improve services to less than 5 days by November 2018.
- **Cyber Security:** Chief Information Office will continue to implement the 8-point cyber security program to better ensure OPG remains vigilant, secure and resilient against growing and emerging threats. This is in direct support of the OPG Board Policy on Cyber Security.
- **Strategic Long-Term Accommodation Plan:** Real Estate & Services will partner with business units across OPG to develop a long-term accommodation strategy to optimize owned and lease premises.
- **Infrastructure Life Cycle Planning:** Real Estate & Services will undertake an initiative to optimize infrastructure capital investment through life cycle planning to maintain aging assets and facilities.

ONTARIO POWER GENERATION

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Nov. 9, 2017

# OPG REPORTS 2017 THIRD QUARTER FINANCIAL RESULTS

## *Darlington Refurbishment Project Remains on Time and on Budget at One-Year Mark*

**Toronto:** – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $131 million for the third quarter of 2017, compared to $194 million for the same period in 2016.

"The Company's focus continues to be on ensuring the success of the Darlington Refurbishment Project. After the one-year mark of work on Darlington's Unit 2, Canada's largest clean energy project remains on time and on budget," said Jeff Lyash, OPG President and CEO. "This is a ten-year project that will extend the life of the Darlington nuclear plant by 30 years, boosting Ontario's GDP by $90 billion and creating more than 14,000 jobs."

The 2017 Long-Term Energy Plan issued by Ontario's Ministry of Energy in October 2017 recognizes the refurbishment of Ontario's nuclear generating fleet as the most cost-effective option for producing emission-free baseload generation to meet Ontario's future needs and reaffirms the Province's commitment to the refurbishment of the four units at the Darlington Nuclear Generating Station (GS). OPG's Enterprise Total Generating Cost, which measures the overall productivity of the Company's nuclear, hydroelectric and thermal generating assets, was 4.8 cents per kilowatt hour for the first nine months of 2017.

Lyash continued, "I am also pleased with the strong performance of our Pickering Nuclear plant, which has so far generated 2.1 terawatt hours of electricity more than last year. We are applying for a licence to extend the operation of the station until 2024. This will ensure a reliable, clean source of low cost power during the Darlington Refurbishment Project and avoid 17 million tonnes of carbon emissions. The 2017 Long-Term Energy Plan confirms the value to customers of continuing Pickering operations to 2024."

"The successful performance of our assets is built around a strong safety culture. This quarter, the Canadian Nuclear Safety Commission has once again given our Pickering and Darlington stations the highest possible safety ratings," Lyash went on to say. "Darlington has now achieved this rating for eight consecutive years and Pickering has achieved the highest possible safety rating for the second year in a row."

“Additionally, OPG successfully completed its first public debt issuance in October, raising $500 million for our general corporate needs and to fund OPG's investment in Ontario’s Fair Hydro Plan,” added Lyash. “This will provide OPG with financial flexibility and further our ability to invest in projects to the benefit of customers and stakeholders.”

The earnings for the third quarter of 2017 were impacted by the expected year-over-year decline in generation revenue, reflecting lower nuclear electricity generation due to the refurbishment outage for Unit 2 at the Darlington GS without the resetting of base regulated prices, largely offset by higher generation from the strong performance of the Pickering GS. The lower earnings were mitigated by lower operations, maintenance and administration (OM&A) expenses across all business segments.

OPG provides electricity at a price that is 40 per cent less than other generators and is the only electricity generator in Ontario that has its prices set through a public hearing process by the Ontario Energy Board (OEB). Earlier in 2017, OPG completed the public hearing process for its current application with the OEB that will set prices for the Company’s nuclear and most of its hydroelectric generation for the next five years, with a proposed effective date of January 1, 2017. The OEB is expected to make a decision on the rate application prior to the end of the year. In the meantime, OPG is operating under base regulated prices that were set in 2014 and do not reflect this year’s reduced nuclear electricity generation, which is primarily due to the Darlington Refurbishment. As in the earlier quarters of this year, the continuation of these prices has negatively affected revenue and net income in the third quarter of 2017. The outcome of the current rate application and the effective date of the new regulated prices are expected to affect OPG’s revenue and net income for the fourth quarter of 2017.

Net income attributable to the Shareholder was $498 million for the nine months ended September 30, 2017, compared to $449 million for the same period in 2016. The gain of $283 million on the sale of OPG’s head office building and parking facility recorded in the second quarter of 2017 offset the year-to-date reduction in generation revenue and was the main driver of the increase in net income for the nine months ended September 30, 2017, compared to the same period in 2016.

Lower earnings on the nuclear fixed asset removal and nuclear waste management segregated funds of $52 million during the third quarter of 2017 and $41 million during the nine months ended September 30, 2017, compared to the corresponding periods in 2016, also contributed to the year-over-year change in net income.

**Generation and Operating Performance**

Electricity generated during the three months ended September 30, 2017 was 19.4 terawatt hours (TWh), compared to 19.5 TWh for the same quarter in 2016. Total electricity generated during the nine months ended September 30, 2017 decreased to 56.0 TWh from 59.9 TWh for the same period in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. For the third quarter of 2017, the decrease was largely offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

*Regulated – Nuclear Generation Segment*

Lower nuclear generation of 0.4 TWh and 4.0 TWh during the three and nine month periods ended September 30, 2017, respectively, was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Offsetting the reduction in generation from the Darlington GS was an increase in generation of 0.9 TWh and 2.1 TWh from the strong performance of the Pickering GS during the three and nine month periods ended September 30, 2017, respectively.

For the three months ended September 30, 2017, the unit capability factor for the operating units at the Darlington GS was 96.2 per cent, compared to 89.6 per cent for the same quarter in 2016. The increase was primarily due to a lower number of planned outage days during the third quarter of 2017. For the nine months ended September 30, 2017, the unit capability factor for the operating units at the Darlington GS was 82.1 per cent, compared to 87.6 per cent for the same period in 2016. The decrease was primarily a result of a higher number of planned outage days at the station in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

At the Pickering GS, the unit capability factor increased to 88.7 per cent and 83.8 per cent for the three and nine month periods ended September 30, 2017, respectively, compared to 77.3 and 73.8 per cent for the same periods in 2016, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

*Regulated – Hydroelectric Segment*

Higher generation from the regulated hydroelectric stations of 0.4 TWh and 0.7 TWh during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 87.6 per cent at these stations in the third quarter of 2017 was higher than 84.1 per cent for the same quarter in 2016, primarily due to a higher number of planned outage days in 2016 as a result of refurbishing the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. For the nine months ended September 30, 2017, the availability of the stations marginally decreased to 89.0 per cent, from 89.8 per cent for the same period in 2016. The marginal decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

*Contracted Generation Portfolio Segment*

Lower generation from the Contracted Generation Portfolio of 0.1 TWh and 0.6 TWh during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was mainly due to lower generation from the segment's hydroelectric plants.

The availability of these hydroelectric stations for the three months ended September 30, 2017 was 66.1 per cent, compared to 68.2 per cent for the same quarter in 2016. The stations' availability for the nine months ended September 30, 2017 was 76.9 per cent, compared to 79.6 per cent for the same period in 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

*Total Generating Cost*

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended September 30, 2017 was $46.65, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric electricity generation adjusted for surplus baseload generation, partially offset by the expected reduction in nuclear electricity generation due to the Unit 2 refurbishment outage at the Darlington GS. The Enterprise Total Generating Cost per MWh for the nine months ended September 30, 2017 was $47.77, compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, which was largely offset by lower OM&A expenses before the impact of regulatory variance and deferral accounts and higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 per MWh lower for the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

**Generation Development**

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the third quarter of 2017 were as follows:

*Darlington Refurbishment*

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling and islanding of the reactor was completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies is in progress and expected to continue through the first quarter of 2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building is expected to be completed in November 2017. The completion of the Heavy Water Storage and Drum Handling Facility, which has been delayed due to challenges with construction, will resume following the substantial completion of the Re-tube Waste Processing Building. The Heavy Water Storage and Drum Handling Facility is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. OPG is in the process of finalizing the increased cost estimate for the Heavy Water Storage and Drum Handling Facility. The change in the cost estimate for the facility will not impact the overall Darlington Refurbishment project budget of $12.8 billion, as it will be accommodated within that budget. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

In addition to the execution of refurbishment activities for Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit.

Total life-to-date capital expenditures on the project were approximately $4.1 billion as at September 30, 2017.

*Ranney Falls Hydroelectric GS*

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

*Nanticoke Solar Facility*

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million.

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

| *(millions of dollars – except where noted)* | Three Months Ended September 30 2017 | 2016 | Nine Months Ended September 30 2017 | 2016 |
|---|---|---|---|---|
| Revenue | **1,217** | 1,400 | **3,539** | 4,265 |
| Fuel expense | **185** | 187 | **518** | 541 |
| Gross margin | **1,032** | 1,213 | **3,021** | 3,724 |
| Operations, maintenance and administration | **635** | 666 | **2,054** | 2,061 |
| Depreciation and amortization | **178** | 313 | **517** | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **235** | 232 | **709** | 696 |
| Earnings on Nuclear Segregated Funds - (a reduction to expenses) | **(196)** | (248) | **(579)** | (620) |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| Other net expenses (gains) | **11** | 13 | **(350)** | 12 |
| Income before interest and income taxes | **180** | 248 | **699** | 662 |
| Net interest expense | **21** | 28 | **56** | 92 |
| Income tax expense | **19** | 22 | **128** | 109 |
| Net income | **140** | 198 | **515** | 461 |
| **Net income attributable to the Shareholder** | **131** | 194 | **498** | 449 |
| **Net income attributable to non-controlling interest** [1] | **9** | 4 | **17** | 12 |
| ***Income (loss) before interest and income taxes*** | | | | |
| Electricity generation business segments | **217** | 238 | **436** | 736 |
| Regulated – Nuclear Waste Management | **(36)** | 18 | **(123)** | (70) |
| Services, Trading, and Other Non-Generation | **(1)** | (8) | **386** | (4) |
| Total income before interest and income taxes | **180** | 248 | **699** | 662 |
| ***Cash flow*** | | | | |
| Cash flow provided by operating activities | **485** | 530 | **698** | 1,211 |
| ***Electricity generation (TWh)*** | | | | |
| Regulated – Nuclear Generation | **11.3** | 11.7 | **30.6** | 34.6 |
| Regulated – Hydroelectric | **7.3** | 6.9 | **23.5** | 22.8 |
| Contracted Generation Portfolio [2] | **0.8** | 0.9 | **1.9** | 2.5 |
| Total electricity generation | **19.4** | 19.5 | **56.0** | 59.9 |
| ***Nuclear unit capability factor (per cent)*** [3] | | | | |
| Darlington Nuclear GS | **96.2** | 89.6 | **82.1** | 87.6 |
| Pickering Nuclear GS | **88.7** | 77.3 | **83.8** | 73.8 |
| ***Availability (per cent)*** | | | | |
| Regulated – Hydroelectric | **87.6** | 84.1 | **89.0** | 89.8 |
| Contracted Generation Portfolio – hydroelectric stations | **66.1** | 68.2 | **76.9** | 79.6 |
| ***Equivalent forced outage rate*** | | | | |
| Contracted Generation Portfolio – thermal stations | **2.6** | 2.1 | **6.0** | 1.3 |
| *Enterprise Total Generating Cost per MWh ($/MWh)* [4] | **46.65** | 50.72 | **47.77** | 46.74 |
| *Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended September 30, 2017 and December 31, 2016 (%)* [4] | | | **4.4** | 4.2 |
| *Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended September 30, 2017 and December 31, 2016 (times)* [4] | | | **4.2** | 5.1 |

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise Total Generating Cost per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and nine months ended September 30, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Common Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended September 30, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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# ONTARIO POWER GENERATION INC.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## 2017 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION

# ONTARIO POWER GENERATION INC.
# MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

## FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan or the Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

## THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

### In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

| *(MW)* | As at September 30 2017 | As at December 31 2016 |
|---|---|---|
| Regulated – Nuclear Generation [1] | **5,728** | 5,728 |
| Regulated – Hydroelectric | **6,426** | 6,421 |
| Contracted Generation Portfolio [2] | **4,056** | 4,028 |
| Total | **16,210** | 16,177 |

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

## HIGHLIGHTS

### Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Revenue | **1,217** | 1,400 | **3,539** | 4,265 |
| Fuel expense | **185** | 187 | **518** | 541 |
| Gross margin | **1,032** | 1,213 | **3,021** | 3,724 |
| Operations, maintenance and administration | **635** | 666 | **2,054** | 2,061 |
| Depreciation and amortization | **178** | 313 | **517** | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **235** | 232 | **709** | 696 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(196)** | (248) | **(579)** | (620) |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| Property taxes | **8** | 12 | **30** | 35 |
| | **849** | 964 | **2,702** | 3,085 |
| Income before other losses (gains), interest and income taxes | **183** | 249 | **319** | 639 |
| Other losses (gains) | **3** | 1 | **(380)** | (23) |
| Income before interest and income taxes | **180** | 248 | **699** | 662 |
| Net interest expense | **21** | 28 | **56** | 92 |
| Income before income taxes | **159** | 220 | **643** | 570 |
| Income tax expense | **19** | 22 | **128** | 109 |
| Net income | **140** | 198 | **515** | 461 |
| Net income attributable to the Shareholder | **131** | 194 | **498** | 449 |
| Net income attributable to non-controlling interest [1] | **9** | 4 | **17** | 12 |
| *Electricity production (TWh)* [2] | **19.4** | 19.5 | **56.0** | 59.9 |
| *Cash flow provided by operating activities* | **485** | 530 | **698** | 1,211 |

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

*Significant factors that reduced income before interest and income taxes:*

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in fewer unplanned and planned outage days at the station. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings of $54 million from the Regulated – Nuclear Waste Management segment, primarily due to a decrease in earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds).
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

*Significant factor that increased income before interest and income taxes:*

- Lower operations, maintenance and administration (OM&A) expenses of $31 million across all business segments.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest income.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of income tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

*Significant factor that increased income before interest and income taxes:*

- The gain on the sale of OPG's head office premises and associated parking facility recorded in the Services, Trading, and Other Non-Generation segment in the second quarter of 2017. The sale of these non-core real estate assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on the sale was $283 million, which is net of tax effects of $95 million.

*Significant factors that reduced income before interest and income taxes:*

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from the Pickering GS.
- Lower earnings of $53 million from the Regulated – Nuclear Waste Management segment, primarily due to a decrease in earnings on the Nuclear Segregated Funds.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.
- Lower rental revenue of $16 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the sale of the head office premises.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

## Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

| *(millions of dollars)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| *Income (loss) before interest and income taxes* | | | | |
| Regulated – Nuclear Generation | **20** | 47 | **(267)** | 17 |
| Regulated – Hydroelectric | **122** | 117 | **474** | 500 |
| Contracted Generation Portfolio | **75** | 74 | **229** | 219 |
| Total electricity generation business segments | **217** | 238 | **436** | 736 |
| Regulated – Nuclear Waste Management | **(36)** | 18 | **(123)** | (70) |
| Services, Trading, and Other Non-Generation | **(1)** | (8) | **386** | (4) |
| | **180** | 248 | **699** | 662 |

## Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

| *(TWh)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Regulated – Nuclear Generation | **11.3** | 11.7 | **30.6** | 34.6 |
| Regulated – Hydroelectric | **7.3** | 6.9 | **23.5** | 22.8 |
| Contracted Generation Portfolio [1] | **0.8** | 0.9 | **1.9** | 2.5 |
| Total OPG electricity generation | **19.4** | 19.5 | **56.0** | 59.9 |
| Total electricity generation by all other generators in Ontario [2] | **16.6** | 19.5 | **51.7** | 53.8 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. This was mainly due to lower electricity generation of 0.4 TWh and 4.0 TWh from the Regulated – Nuclear Generation segment for the three and nine month periods ended September 30, 2017, respectively. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric stations, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Baseload generation supply surplus in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the corresponding periods in 2016. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

## Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

## Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The decrease in cash flow for the nine months ended September 30, 2017 also was partially offset by lower pension plan contributions in 2017 reflecting an updated actuarial valuation of the OPG registered pension plan filed with the Financial Services Commission of Ontario, as well as the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

## Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on the sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB.

### Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income, as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

### Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows, partly offset by the expected reduction in nuclear electricity generation due to the Unit 2 refurbishment outage at the Darlington GS.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

## Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh of $58.75 for the three months ended September 30, 2017 was comparable to $58.55 for the same quarter in 2016, as the higher electricity generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was largely offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

## Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows net of higher fuel expense, lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

## Recent Developments

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long-Term Energy Plan (2017 LTEP) that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous Long-Term Energy Plan issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 Long-Term Energy Plan. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business growth opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies.

Ontario's Fair Hydro Plan

The *Ontario Fair Hydro Plan Act, 2017* (the Act) received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiative are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The aim of the Plan is to reduce electricity bills for residential, farm, small businesses and other eligible consumers by refinancing a portion of the Global Adjustment costs over a longer time period. The legislation appointed OPG as the Financial Services Manager of the Fair Hydro Plan and provides for a financing entity to be established by OPG. The regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

OPG's Board of Directors, which had established a Special Committee to provide oversight on behalf of the Board of Directors, has conditionally approved OPG's involvement with the Fair Hydro Plan on commercial terms. OPG is in the process of establishing the Fair Hydro Trust (the Trust) as the financing entity contemplated by the Act. The majority unitholder and beneficiary of the Trust will be a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the Company's assets and operations. Through this ownership and OPG's control over the key activities of the Trust, the Company expects to consolidate the financial results of the Trust in accordance with US GAAP, commencing in the fourth quarter of 2017.

In order for the Trust to finance the deferred portion of the Global Adjustment costs, it will incur senior debt from capital markets and subordinated debt from OPG, which it will use to periodically purchase an investment interest in the deferred Global Adjustment costs from the IESO. The Trust's investment will attract a financing amount and other related fees, which will be payable by the eligible consumers in the future.

Through an equity injection in OPG, the Province is expected to provide 44 percent of the total funding requirement related to the Trust's investment interest in the deferred Global Adjustment costs. OPG will invest the proceeds from the equity injection into subordinated debt issued to the Trust. A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province is in progress. OPG's Board of Directors' approval and a Shareholder Resolution are expected later in the year to authorize the amendment.

OPG expects to provide five percent of the total funding requirement related to the Trust's investment interest in the deferred Global Adjustment costs, through its subordinated debt investment in the Trust. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund its portion of the subordinated debt investment. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

The first set of transactions of the Trust is expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

## CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

### Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also finalizing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end-of-life assumptions for the Pickering GS are currently set at the end of 2020. These assumptions are expected to be reassessed in line with OPG's plans to extend the station's operation to 2024 when the work on the fuel channel analysis, other technical feasibility assessments and safety case consistent with submissions for the CNSC's approval, discussed below, provides the necessary technical confidence to support a change in the accounting end-of-life date. The technical work undertaken to date has yielded positive results, which will go toward supporting a change in the accounting end-of-life assumptions. OPG's current application with the OEB for new base regulated prices, presently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operations period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG is undertaking a Periodic Safety Review (PSR), which will confirm that extending operations of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR) and the Integrated Implementation Plan (IIP). SFRs and GAR have been submitted to the CNSC, with the IIP on track for CNSC submission in November 2017.

- Work continues on the overhaul and upgrade of Unit 2 of the DeCew Falls hydroelectric GS, with completion of the power assembly, refurbishment of the turbine and final delivery of the major components, and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.

- During the third quarter, as part of a continued focus on operating performance and efficiency improvement, OPG opened an amalgamated control room located at the Saunders hydroelectric GS that will control all operational activities at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for the removal of the powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

## Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

| Project | Capital expenditures | | Approved budget | Expected in-service date | Current status |
|---|---|---|---|---|---|
| *(millions of dollars)* | Year-to-date | Life-to-date | | | |
| Darlington Refurbishment | 924 | 4,109 | 12,800 [1] | First unit - 2020<br>Last unit - 2026 | The setup of specialized tooling and equipment needed for the removal of Unit 2 reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the removal of fuel channel assemblies is in progress. Construction activities on the Heavy Water Storage and Drum Handling Facility will recommence following the substantial completion of the Re-tube Waste Processing Building in November 2017. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget. |
| Peter Sutherland Sr. Hydroelectric GS | 38 | 274 | 300 | 2017 | The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress. |
| Ranney Falls Hydroelectric GS | 17 | 20 | 77 | 2019 | Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway. The project is tracking on schedule and on budget. |
| Nanticoke Solar Facility | 1 | 2 | 107 | 2019 | Project definition work is continuing, with construction planned to commence in the first quarter of 2018. |
| Deep Geologic Repository (DGR) for low and intermediate level radioactive waste (L&ILW) | 7 [2] | 202 [2] | | | On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is assessing the new request. |

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS, including the costs of the pre-requisite projects in support of the execution phase of the refurbishment.

[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies is in progress and expected to continue through the first quarter of 2018. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved IIP for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building is expected to be completed in November 2017. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF will recommence following the substantial completion of the Re-tube Waste Processing Building. This sequencing ensures that the necessary resources are available for both projects and, through resource levelling, supports improved execution and cost efficiency of these projects.

The HWSF is expected to be completed by early 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. OPG is in the process of finalizing the increased cost estimate for the HWSF. The change in the cost estimate for the HWSF will not impact the overall Darlington Refurbishment budget of $12.8 billion, as it will be accommodated within that budget. Taking into account the execution performance of the Unit 2 refurbishment, the overall Darlington Refurbishment project continues to track on budget.

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the forecast Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to

the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work has been substantially completed and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act*. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions would be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG is assessing the request. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

## Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year over year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

In addition to an increase in the nuclear rate base to reflect the planned placement in service of capital expenditures for the Darlington Refurbishment project, the application seeks an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices, effective in 2017. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The public hearing process for the application was completed in the second quarter of 2017. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. Following the decision, the OEB is expected to issue an order establishing and implementing the new regulated prices, including rate riders, based on the findings in the decision.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG continues to engage with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington nuclear generating stations.

OPG is also developing recruitment plans targeting Indigenous peoples and, in October 2017, participated in several Indigenous-specific career fairs.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

## Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, presently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period. The continuation of existing regulated prices during 2017 prior to the issuance of the OEB's decision has reduced income, particularly from the Regulated – Nuclear Generation segment, and lowered ROE Excluding AOCI.

In its application, OPG has requested January 1, 2017 as the effective date of the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. The issuance of the decision in the fourth quarter of 2017 would result in OPG's revenue for that quarter reflecting the impact of the new regulated prices, including the impact of any retrospective change in the regulated prices for the period between their effective date and their implementation date. As such, the OEB's decision on the effective date, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results for the fourth quarter of 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined

with the expiry of rate riders in effect to the end of 2016, the year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and work on the Ranney Falls GS expansion, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and the funded status of the two segregated funds, discussed below.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA Reference Plan. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

The Fair Hydro Plan is not expected to have a material impact on the Company's net income for the year ended December 31, 2017.

## DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

### Regulated – Nuclear Generation Segment

| *(millions of dollars) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Revenue | **739** | 885 | **2,000** | 2,631 |
| Fuel expense | **81** | 79 | **217** | 239 |
| Gross margin | **658** | 806 | **1,783** | 2,392 |
| Operations, maintenance and administration | **511** | 521 | **1,693** | 1,665 |
| Depreciation and amortization | **116** | 230 | **333** | 691 |
| Property taxes | **7** | 6 | **20** | 19 |
| Income (loss) before other losses, interest, and income taxes | **24** | 49 | **(263)** | 17 |
| Other losses | **4** | 2 | **4** | - |
| Income (loss) before interest and income taxes | **20** | 47 | **(267)** | 17 |

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease for the nine months ended September 30, 2017 was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, mainly due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Unit Capability Factor *(%)* [1] | | | | |
| Darlington GS | **96.2** | 89.6 | **82.1** | 87.6 |
| Pickering GS | **88.7** | 77.3 | **83.8** | 73.8 |

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days in 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days in the first half of 2017, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

**Regulated – Nuclear Waste Management Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **33** | 36 | **90** | 102 |
| Operations, maintenance and administration | **35** | 38 | **96** | 108 |
| Accretion on nuclear fixed asset removal and nuclear waste management liabilities | **230** | 228 | **696** | 684 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(196)** | (248) | **(579)** | (620) |
| (Loss) Income before interest and income taxes | **(36)** | 18 | **(123)** | (70) |

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine month periods ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account, reflecting earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (rate of return guarantee) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine month periods ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds recognized in net income during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guarantee. The higher earnings on both funds during the three and nine month periods ended September 30, 2016 reflected market returns and the rate of return guarantee, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded. Market returns and the rate of return guarantee in the third quarter of 2016 were higher than the funding liabilities' growth rate reflected in fund earnings during 2017, resulting in a year-over-year decrease in the amount of earnings recognized in

net income. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the fourth quarter of 2017, as they are expected to continue to be offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's regulated prices, and thereafter by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*.

**Regulated – Hydroelectric Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue [1] | **327** | 350 | **1,069** | 1,148 |
| Fuel expense | **88** | 88 | **258** | 259 |
| Gross margin | **239** | 262 | **811** | 889 |
| Operations, maintenance and administration | **81** | 87 | **232** | 238 |
| Depreciation and amortization | **34** | 56 | **103** | 169 |
| Property tax | **1** | 1 | **1** | 1 |
| Income before other losses (gains), interest and income taxes | **123** | 118 | **475** | 481 |
| Other losses (gains) | **1** | 1 | **1** | (19) |
| Income before interest and income taxes | **122** | 117 | **474** | 500 |

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the deferral of outages and repairs and maintenance work during the high water period in 2017.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by lower OM&A expenses in the third quarter of 2017.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory

accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric Availability *(%)* | **87.6** | 84.1 | **89.0** | 89.8 |

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outage days in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in the Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

### Contracted Generation Portfolio Segment

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **141** | 149 | **431** | 431 |
| Fuel expense | **15** | 19 | **42** | 42 |
| Gross margin | **126** | 130 | **389** | 389 |
| Operations, maintenance and administration | **39** | 44 | **118** | 129 |
| Depreciation and amortization | **20** | 19 | **59** | 56 |
| Accretion on fixed asset removal liabilities | **3** | 2 | **7** | 6 |
| Property taxes | **-** | 1 | **5** | 6 |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| Income before other loss, interest and income taxes | **75** | 75 | **229** | 220 |
| Other loss | **-** | 1 | **-** | 1 |
| Income before interest and income taxes | **75** | 74 | **229** | 219 |

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric Availability *(%)* | **66.1** | 68.2 | **76.9** | 79.6 |
| Thermal EFOR *(%)* | **2.6** | 2.1 | **6.0** | 1.3 |

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

**Services, Trading, and Other Non-Generation Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **9** | 15 | **36** | 52 |
| Fuel expense | **1** | 1 | **1** | 1 |
| Gross margin | **8** | 14 | **35** | 51 |
| Operations, maintenance and administration | **1** | 11 | **2** | 20 |
| Depreciation and amortization | **8** | 8 | **22** | 25 |
| Accretion on fixed asset removal liabilities | **2** | 2 | **6** | 6 |
| Property taxes | **-** | 4 | **4** | 9 |
| (Loss) income before other gains, interest, and income taxes | **(3)** | (11) | **1** | (9) |
| Other gains | **(2)** | (3) | **(385)** | (5) |
| (Loss) income before interest and income taxes | **(1)** | (8) | **386** | (4) |

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings reflected higher OM&A expenses in the third quarter of 2016 as a result of a write-off of project expenditures and the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS. Expenditures incurred in connection with the decommissioning activities at the Lambton GS are charged against a previously established decommissioning provision.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 as well as lower OM&A expenses, partially offset by a decrease in rental revenue due to the sale of the head office premises.

## LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on the Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 were as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Cash and cash equivalents, beginning of period | **242** | 295 | **186** | 464 |
| Cash flow provided by operating activities | **485** | 530 | **698** | 1,211 |
| Cash flow used in investing activities | **(463)** | (390) | **(720)** | (1,253) |
| Cash flow provided by (used in) financing activities | **16** | (9) | **116** | 4 |
| Net increase (decrease) | **38** | 131 | **94** | (38) |
| Cash and cash equivalents, end of period | **280** | 426 | **280** | 426 |

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

### Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to a Shareholder Declaration and a Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place as early as in the fourth quarter of 2017.

## Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of LME's credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at September 30, 2017, there were long-term borrowings of $800 million outstanding under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes and the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

## Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017, with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

## BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

| *(millions of dollars) (unaudited)* | As At September 30 2017 | As At December 31 2016 |
|---|---|---|
| **Property, plant and equipment - net** | **20,801** | 19,998 |
| The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense. | | |
| **Nuclear fixed asset removal and nuclear waste management funds** *(current and non-current portions)* | **16,534** | 15,984 |
| The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities. | | |
| **Short-term debt** | **160** | 2 |
| The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017. | | |
| **Fixed asset removal and nuclear waste management liabilities** | **20,075** | 19,484 |
| The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities. | | |

## Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

## CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

## RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

### Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the L&ILW DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON; however, the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

### Risks to Maintaining Financial Strength

Commodity Markets

*Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.*

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

| | 2017 [1] | 2018 | 2019 |
|---|---|---|---|
| Estimated fuel requirements hedged [2] | 73% | 73% | 69% |

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

*OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.*

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

*OPG's financial performance can be affected by its trading activities.*

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

*Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.*

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Ontario's Fair Hydro Plan

*OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.*

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility in respect of pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The final report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at a prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, which is recognized as a regulatory asset on the Company's consolidated

balance sheet. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

## RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

| | Three Months Ended September 30 | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| *(millions of dollars) (unaudited)* | **Revenue** | **Expense** | **Revenue** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **2** | **-** | 1 | - |
| Services | **-** | **3** | - | 3 |
| Dividends | **2** | **-** | 2 | - |
| Province of Ontario | | | | |
| Decommissioning Fund excess funding [1] | **-** | **(44)** | - | 201 |
| Used Fuel Fund rate of return guarantee and excess funding [1] | **-** | **(39)** | - | 295 |
| Gross revenue charges | **-** | **27** | - | 28 |
| ONFA guarantee fee | **-** | **2** | - | 2 |
| Other | **-** | **2** | - | - |
| OEFC | | | | |
| Gross revenue charges | **-** | **62** | - | 57 |
| Interest expense on long-term notes | **-** | **40** | - | 42 |
| Income taxes, net of investment tax credits | **-** | **23** | - | 28 |
| IESO | | | | |
| Electricity related revenue | **1,126** | **4** | 1,293 | 7 |
| | **1,130** | **80** | 1,296 | 663 |

| | Nine Months Ended September 30 | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| *(millions of dollars) (unaudited)* | **Revenue** | **Expense** | **Revenue** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **7** | **-** | 4 | - |
| Services | **1** | **8** | 1 | 12 |
| Dividends | **6** | **-** | 4 | - |
| Province of Ontario | | | | |
| Decommissioning Fund excess funding [1] | **-** | **164** | - | 137 |
| Used Fuel Fund rate of return guarantee and excess funding [1] | **-** | **217** | - | 190 |
| Gross revenue charges | **-** | **84** | - | 91 |
| ONFA guarantee fee | **-** | **6** | - | 6 |
| Other | **-** | **3** | - | - |
| OEFC | | | | |
| Gross revenue charges | **-** | **156** | - | 147 |
| Interest expense on long-term notes | **-** | **122** | - | 127 |
| Income taxes, net of investment tax credits | **-** | **132** | - | 112 |
| IESO | | | | |
| Electricity related revenue | **3,228** | **11** | 3,894 | 22 |
| | **3,242** | **903** | 3,903 | 844 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| *(millions of dollars) (unaudited)* | **September 30 2017** | **December 31 2016** |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO | **346** | 421 |
| OEFC | **3** | 1 |
| PEC | **2** | 4 |
| Province of Ontario | **5** | 2 |
| Available-for-sale securities | | |
| Hydro One shares | **190** | 212 |
| Accounts payable and accrued charges | | |
| OEFC | **37** | 61 |
| Province of Ontario | **6** | 2 |
| IESO | **2** | 2 |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,245** | 3,295 |

OPG may hold interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected in the fourth quarter of 2017.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

## QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

| *(millions of dollars - except where noted)* *(unaudited)* | **September 30 2017** | **June 30 2017** | **March 31 2017** | **December 31 2016** |
|---|---|---|---|---|
| Revenue | **1,217** | 1,146 | 1,176 | 1,388 |
| Net income (loss) | **140** | 307 | 68 | (8) |
| Less: Net income attributable to non-controlling interest | **9** | 4 | 4 | 5 |
| Net income (loss) attributable to the Shareholder | **131** | 303 | 64 | (13) |
| **Per common share, attributable to the Shareholder *(dollars)*** | **$0.51** | $1.18 | $0.25 | ($0.05) |

| *(millions of dollars - except where noted)* *(unaudited)* | **September 30 2016** | **June 30 2016** | **March 31 2016** | **December 31 2015** |
|---|---|---|---|---|
| Revenue | 1,400 | 1,387 | 1,478 | 1,312 |
| Net income (loss) | 198 | 135 | 128 | (100) |
| Less: Net income attribute to the non-controlling interest | 4 | 3 | 5 | 1 |
| Net income (loss) attributable to the Shareholder | 194 | 132 | 123 | (101) |
| **Per common share, attributable to the Shareholder *(dollars)*** | $0.76 | $0.51 | $0.48 | ($0.39) |

### Trends

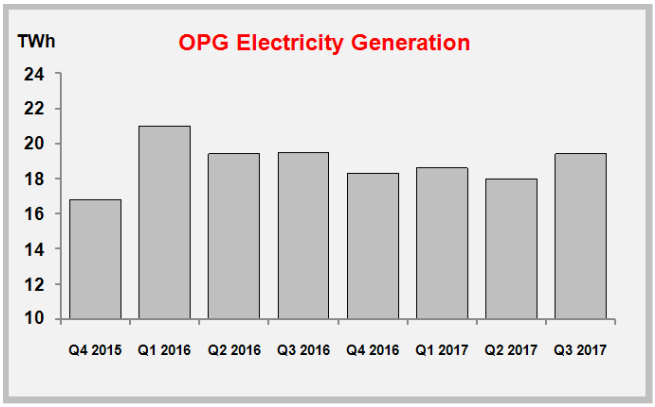
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

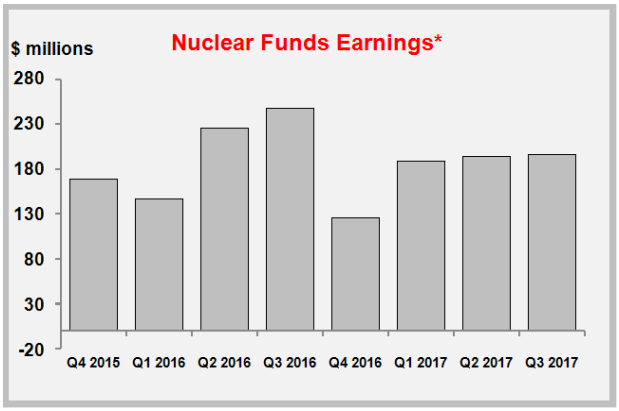
quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation has been reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is scheduled to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of the earnings on the Nuclear Segregated Funds is mitigated by their funded status.




*net of regulatory variance account

Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under the section, *Quarterly Financial Highlights*.

## SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

| | **Twelve Months Ended** | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **September 30 2017** | **December 31 2016** |
| ROE Excluding AOCI | | |
| Net income attributable to the Shareholder | **485** | 436 |
| Divided by: Average equity attributable to the Shareholder, excluding AOCI | **11,055** | 10,442 |
| **ROE Excluding AOCI *(percent)*** | **4.4** | 4.2 |

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

| | Twelve Months Ended | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **September 30 2017** | **December 31 2016** |
| FFO before interest | | |
| Cash flow provided by operating activities | **1,082** | 1,595 |
| Add: Interest paid | **270** | 269 |
| Less: Interest capitalized to fixed and intangible assets | **(161)** | (141) |
| Less: Changes to non-cash working capital balances | **38** | 42 |
| FFO before interest | **1,229** | 1,765 |
| Adjusted interest expense | | |
| Net interest expense | **84** | 120 |
| Add: Interest income | **8** | 7 |
| Add: Interest capitalized to fixed and intangible assets | **161** | 141 |
| Add: Interest related to regulatory assets and liabilities | **43** | 30 |
| Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1] | **-** | 45 |
| Adjusted interest expense | **296** | 343 |
| **FFO Adjusted Interest Coverage** *(times)* | **4.2** | 5.1 |

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Enterprise TGC | | | | |
| Total OM&A expenses | **635** | 666 | **2,054** | 2,061 |
| Total fuel expense | **185** | 187 | **518** | 541 |
| Total capital expenditures | **476** | 444 | **1,335** | 1,162 |
| Less: Darlington Refurbishment capital and OM&A costs | **(328)** | (269) | **(943)** | (717) |
| Less: Other generation development project capital and OM&A costs | **(17)** | (42) | **(53)** | (121) |
| Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory variance and deferral accounts | **4** | 35 | **(19)** | 76 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(13)** | (18) | **(42)** | (50) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **13** | 5 | **47** | 38 |
| Less: OM&A expenses ancillary to electricity generation business | **(4)** | (5) | **(13)** | (17) |
| Other adjustments | **(3)** | (12) | **(7)** | (15) |
| | **948** | 991 | **2,877** | 2,958 |
| Adjusted electricity generation *(TWh)* | | | | |
| Total OPG electricity generation | **19.4** | 19.5 | **56.0** | 59.9 |
| Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities | **0.9** | 0.1 | **4.2** | 3.4 |
| | **20.3** | 19.6 | **60.2** | 63.3 |
| **Enterprise TGC per MWh *($/MWh)*** [1] | **46.65** | 50.72 | **47.77** | 46.74 |

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

| *(millions of dollars – except where noted) (unaudited)* | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Nuclear TGC | | | | |
| Regulated – Nuclear Generation OM&A expenses | **511** | 521 | **1,693** | 1,665 |
| Regulated – Nuclear Generation fuel expense | **81** | 79 | **217** | 239 |
| Regulated – Nuclear Generation capital expenditures | **409** | 339 | **1,150** | 896 |
| Less: Darlington Refurbishment capital and OM&A costs | **(328)** | (269) | **(943)** | (717) |
| Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts | **5** | 31 | **6** | 84 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(13)** | (18) | **(42)** | (50) |
| Less: Regulated - Nuclear Generation OM&A expenses ancillary to electricity generation business | **(1)** | (1) | **(3)** | (4) |
| Other adjustments | **1** | 3 | **(1)** | (1) |
| | **665** | 685 | **2,077** | 2,112 |
| Nuclear electricity generation (TWh) | **11.3** | 11.7 | **30.6** | 34.6 |
| **Nuclear TGC per MWh (*$/MWh*)** [1] | **58.75** | 58.55 | **67.87** | 61.07 |

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric TGC | | | | |
| Regulated – Hydroelectric OM&A expenses | **81** | 87 | **232** | 238 |
| Regulated – Hydroelectric fuel expense | **88** | 88 | **258** | 259 |
| Contracted Generation Portfolio OM&A expenses | **39** | 44 | **118** | 129 |
| Contracted Generation Portfolio fuel expense | **15** | 19 | **42** | 42 |
| Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures | **56** | 92 | **141** | 231 |
| Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs | **(17)** | (41) | **(52)** | (117) |
| Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio | **(39)** | (51) | **(119)** | (126) |
| (Less) Add: Regulated – Hydroelectric OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts | **(1)** | 4 | **(25)** | (8) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **13** | 5 | **47** | 38 |
| Other adjustments | **(1)** | (1) | **-** | (1) |
| | **234** | 246 | **642** | 685 |
| Adjusted hydroelectric electricity generation *(TWh)* | | | | |
| Regulated – Hydroelectric electricity generation | **7.3** | 6.9 | **23.5** | 22.8 |
| Contracted Generation Portfolio electricity generation | **0.8** | 0.9 | **1.9** | 2.5 |
| Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities | **0.8** | 0.1 | **4.1** | 3.4 |
| | **8.9** | 7.9 | **29.5** | 28.7 |
| **Hydroelectric TGC per MWh *($/MWh)*** [1] | **26.20** | 31.01 | **21.74** | 23.99 |

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

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# ONTARIO POWER GENERATION INC.

# INTERIM CONSOLIDATED FINANCIAL STATEMENTS
# (unaudited)

**SEPTEMBER 30, 2017**

ONTARIO POWER GENERATION

# INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

| *(millions of dollars except where noted)* | Three Months Ended September 30 2017 | 2016 | Nine Months Ended September 30 2017 | 2016 |
|---|---|---|---|---|
| **Revenue** *(Note 12)* | **1,217** | 1,400 | **3,539** | 4,265 |
| Fuel expense *(Note 12)* | **185** | 187 | **518** | 541 |
| **Gross margin** | **1,032** | 1,213 | **3,021** | 3,724 |
| **Expenses** *(Note 12)* | | | | |
| Operations, maintenance and administration | **635** | 666 | **2,054** | 2,061 |
| Depreciation and amortization | **178** | 313 | **517** | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **235** | 232 | **709** | 696 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(196)** | (248) | **(579)** | (620) |
| Property taxes | **8** | 12 | **30** | 35 |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| | **849** | 964 | **2,702** | 3,085 |
| **Income before other losses (gains), interest and income taxes** | **183** | 249 | **319** | 639 |
| Other losses (gains) *(Note 12)* | **3** | 1 | **(380)** | (23) |
| **Income before interest and income taxes** | **180** | 248 | **699** | 662 |
| Net interest expense *(Note 5)* | **21** | 28 | **56** | 92 |
| **Income before income taxes** | **159** | 220 | **643** | 570 |
| Income tax expense | **19** | 22 | **128** | 109 |
| **Net income** | **140** | 198 | **515** | 461 |
| **Net income attributable to the Shareholder** | **131** | 194 | **498** | 449 |
| Net income attributable to non-controlling interest | **9** | 4 | **17** | 12 |
| **Basic and diluted net income per common share** *(dollars)* | **0.51** | 0.76 | **1.94** | 1.75 |
| **Common shares outstanding** *(millions)* | **256.3** | 256.3 | **256.3** | 256.3 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

| *(millions of dollars)* | Three Months Ended September 30 2017 | 2016 | Nine Months Ended September 30 2017 | 2016 |
|---|---|---|---|---|
| **Net income** | **140** | 198 | **515** | 461 |
| **Other comprehensive income, net of income taxes** *(Note 7)* | | | | |
| Reclassification to income of amounts related to pension and other post-employment benefits [1] | **3** | 3 | **8** | 9 |
| Reclassification to income of losses on derivatives designated as cash flow hedges [2] | **4** | 4 | **13** | 14 |
| Unrealized (loss) gain on available-for-sale securities [3] | **(4)** | - | **(6)** | 15 |
| Other comprehensive income for the period | **3** | 7 | **15** | 38 |
| **Comprehensive income** | **143** | 205 | **530** | 499 |
| **Comprehensive income attributable to the Shareholder** | **134** | 201 | **513** | 487 |
| Comprehensive income attributable to non-controlling interest | **9** | 4 | **17** | 12 |

[1] Net of income tax expenses of nil and $1 million for the three months ended September 30, 2017 and 2016, respectively. Net of income tax expenses of $2 million and $3 million for the nine months ended September 30, 2017 and 2016, respectively.

[2] Net of income tax expenses of $1 million for the three months ended September 30, 2017 and 2016. Net of income tax expense of $2 million for the nine months ended September 30, 2017 and 2016.

[3] Net of income tax expense of nil for the three months ended September 30, 2017 and 2016. Net of income tax recovery of $1 million and income tax expenses of $5 million for the nine months ended September 30, 2017 and 2016, respectively.

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

| **Nine Months Ended September 30**<br>*(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Operating activities** | | |
| Net income | **515** | 461 |
| Adjust for non-cash items: | | |
| Depreciation and amortization | **517** | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **709** | 696 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(579)** | (620) |
| Pension and other post-employment benefit costs *(Note 8)* | **339** | 351 |
| Deferred income taxes | **50** | (41) |
| Mark-to-market on derivative instruments | **(4)** | 1 |
| Provision for used nuclear fuel and low and intermediate level nuclear waste | **84** | 91 |
| Regulatory assets and liabilities | **(97)** | (82) |
| Provision for materials and supplies | **13** | 38 |
| Other gains | **(374)** | (23) |
| Other | **(35)** | (14) |
| | **1,138** | 1,799 |
| Contributions to nuclear fixed asset removal and nuclear waste management funds | **-** | (112) |
| Expenditures on fixed asset removal and nuclear waste management | **(231)** | (189) |
| Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management | **59** | 49 |
| Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans | **(270)** | (331) |
| Expenditures on restructuring | **(3)** | (3) |
| Distributions received from investments subject to significant influence | **37** | 40 |
| Net changes to other long-term assets and liabilities | **23** | 17 |
| Net changes in non-cash working capital balances *(Note 13)* | **(55)** | (59) |
| **Cash flow provided by operating activities** | **698** | 1,211 |
| **Investing activities** | | |
| Proceeds from sale of property, plant and equipment | **484** | - |
| Purchase of available-for-sale securities | **-** | (213) |
| Proceeds from deposit note *(Note 4)* | **70** | 65 |
| Investment in property, plant and equipment and intangible assets | **(1,274)** | (1,105) |
| **Cash flow used in investing activities** | **(720)** | (1,253) |
| **Financing activities** | | |
| Issuance of long-term debt *(Note 4)* | **800** | - |
| Repayment of long-term debt | **(852)** | (2) |
| Contribution from non-controlling interest | **19** | - |
| Distribution to non-controlling interest | **(11)** | (11) |
| Issuance of short-term notes | **1,458** | 2,916 |
| Repayment of short-term notes | **(1,298)** | (2,899) |
| **Cash flow provided by financing activities** | **116** | 4 |
| Net increase (decrease) in cash and cash equivalents | **94** | (38) |
| **Cash and cash equivalents, beginning of period** | **186** | 464 |
| **Cash and cash equivalents, end of period** | **280** | 426 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| As at<br>*(millions of dollars)* | September 30<br>2017 | December 31<br>2016 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents | **280** | 186 |
| Available-for-sale securities | **190** | 212 |
| Receivables from related parties | **357** | 429 |
| Nuclear fixed asset removal and nuclear waste management funds | **19** | 24 |
| Fuel inventory | **290** | 310 |
| Materials and supplies | **96** | 100 |
| Income taxes recoverable | **11** | - |
| Prepaid expenses | **212** | 198 |
| Other current assets | **108** | 298 |
| | **1,563** | 1,757 |
| **Property, plant and equipment** | **30,491** | 29,315 |
| Less: accumulated depreciation | **9,690** | 9,317 |
| | **20,801** | 19,998 |
| **Intangible assets** | **546** | 503 |
| Less: accumulated amortization | **425** | 404 |
| | **121** | 99 |
| **Other non-current assets** | | |
| Nuclear fixed asset removal and nuclear waste management funds | **16,515** | 15,960 |
| Long-term materials and supplies | **364** | 345 |
| Regulatory assets *(Note 3)* | **6,002** | 5,855 |
| Investments subject to significant influence *(Note 14)* | **313** | 321 |
| Other long-term assets | **27** | 37 |
| | **23,221** | 22,518 |
| | **45,706** | 44,372 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| As at<br>*(millions of dollars)* | September 30 2017 | December 31 2016 |
|---|---|---|
| **Liabilities** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | **1,144** | 1,164 |
| Deferred revenue | **12** | 12 |
| Short-term debt | **160** | 2 |
| Long-term debt due within one year *(Note 4)* | **628** | 1,103 |
| Income taxes payable | **-** | 123 |
| | **1,944** | 2,404 |
| **Long-term debt** *(Note 4)* | **4,840** | 4,417 |
| **Other non-current liabilities** | | |
| Fixed asset removal and nuclear waste management liabilities *(Note 6)* | **20,075** | 19,484 |
| Pension liabilities | **2,867** | 3,012 |
| Other post-employment benefit liabilities | **2,959** | 2,897 |
| Long-term accounts payable and accrued charges | **235** | 213 |
| Deferred revenue | **338** | 298 |
| Deferred income taxes | **890** | 829 |
| Regulatory liabilities *(Note 3)* | **510** | 310 |
| | **27,874** | 27,043 |
| **Equity** | | |
| Common shares [1] | **5,126** | 5,126 |
| Retained earnings | **6,034** | 5,534 |
| Accumulated other comprehensive loss *(Note 7)* | **(277)** | (295) |
| **Equity attributable to the Shareholder** | **10,883** | 10,365 |
| Equity attributable to non-controlling interest | **165** | 143 |
| **Total equity** | **11,048** | 10,508 |
| | **45,706** | 44,372 |

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2017 and December 31, 2016.

Commitments and Contingencies *(Notes 4, 10 and 11)*

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY (UNAUDITED)

| **Nine Months Ended September 30**<br>*(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Common shares** | **5,126** | 5,126 |
| **Retained earnings** | | |
| Balance at beginning of period | **5,534** | 5,098 |
| Net income attributable to the Shareholder | **498** | 449 |
| Reclassification of non-controlling interest on change in ownership interest *(Note 15)* | **2** | - |
| Balance at end of period | **6,034** | 5,547 |
| **Accumulated other comprehensive loss, net of income taxes** | | |
| Balance at beginning of period | **(295)** | (319) |
| Other comprehensive income | **15** | 38 |
| Reclassification of non-controlling interest on change in ownership interest *(Note 15)* | **3** | - |
| Balance at end of period | **(277)** | (281) |
| **Equity attributable to the Shareholder** | **10,883** | 10,392 |
| **Equity attributable to non-controlling interest** | | |
| Balance at beginning of period | **143** | 140 |
| Equity contribution from non-controlling interest *(Note 15)* | **21** | - |
| Reclassification of non-controlling interest on change in ownership interest *(Note 15)* | **(5)** | - |
| Distribution to non-controlling interest | **(11)** | (11) |
| Income attributable to non-controlling interest | **17** | 12 |
| Balance at end of period | **165** | 141 |
| **Total equity** | **11,048** | 10,533 |

*See accompanying notes to the interim consolidated financial statements*

# NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine months ended September 30, 2017 and 2016

## 1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2017 and 2016 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2016. All dollar amounts are presented in Canadian dollars.

Certain of the 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 interim consolidated financial statement presentation.

### Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

## 2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

### Change in Accounting Estimate

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the method used to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs is estimated at approximately $35 million and $105 million for the three and nine months ended September 30, 2017, respectively. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory variance and deferral accounts authorized by the Ontario Energy Board (OEB).

## Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

As part of the project to implement the new revenue standard, OPG is continuing to assess the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include regulated generation revenue from base regulated prices and rate riders established by the OEB, as well as revenue from generation assets under long-term contractual arrangements with the Independent Electricity System Operator (IESO). In March 2017, the American Institute of Certified Public Accountants (AICPA) issued Revenue Recognition Implementation Issue #13-1*, Scope Clarification Regarding Tariff Sales to Regulated Customers*. The draft implementation guidance was developed by the AICPA Power & Utilities task force. This draft guidance concludes that tariff-based revenue from the provision of regulated utility service to a utility's customers is within the scope of Topic 606. OPG has completed its analysis of the impact of Topic 606 on its accounting for generation revenue from base regulated prices and long-term contractual arrangements with the IESO, and has not identified any material differences in the timing or amount of revenue recognition for these streams. The Company continues to assess the impact of Topic 606 on its other revenue streams.

The Company currently expects to apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of concluding on the method of adoption.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance is not expected to have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance is not expected to affect the presentation of OPG's consolidated financial statements.

## 3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at September 30, 2017 and December 31, 2016 are as follows:

| *(millions of dollars)* | **September 30 2017** | **December 31 2016** |
|---|---|---|
| Regulatory assets | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Pension and OPEB Cost Variance Account | **716** | 716 |
| Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 8)* | **552** | 497 |
| Hydroelectric Surplus Baseload Generation Variance Account | **327** | 210 |
| Bruce Lease Net Revenues Variance Account | **131** | 95 |
| Other variance and deferral accounts | **137** | 107 |
| | **1,863** | 1,625 |
| Pension and OPEB Regulatory Asset *(Note 8)* | **3,260** | 3,392 |
| Deferred Income Taxes | **879** | 838 |
| Total regulatory assets | **6,002** | 5,855 |
| Regulatory liabilities | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Hydroelectric Water Conditions Variance Account | **143** | 51 |
| Impact Resulting from Changes in Station End-of-Life Dates Deferral Account | **124** | 71 |
| Other variance and deferral accounts | **243** | 188 |
| Total regulatory liabilities | **510** | 310 |

OPG's May 2016 application with the OEB for new regulated prices included a request for new rate riders to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders in effect during 2016. The application also requested the continuation of all applicable existing variance and deferral accounts. In March 2017, the OEB approved a settlement agreement reached by OPG and intervenors on a limited set of issues in the application (Settlement Agreement). Among the settled issues, the agreement provided for the continuation of all applicable existing variance and deferral accounts and accepted a number of variance and deferral account balances for recovery, as requested in OPG's application. The periods of recovery or repayment for the accepted variance and deferral account balances are excluded from the scope of the Settlement Agreement. The Settlement Agreement did not impact OPG's financial results for the three and nine months ended September 30, 2017. The OEB's decision on OPG's application is pending.

As at September 30, 2017 and December 31, 2016, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, and the Nuclear Development Variance Account. As at September 30, 2017 and December 31, 2016, regulatory liabilities for other variance and deferral accounts included the amounts for the Pension & OPEB Cash Payment Variance Account, the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, and the Hydroelectric Incentive Mechanism Variance Account.

## 4. LONG-TERM DEBT

Long-term debt consists of the following:

| *(millions of dollars)* | **September 30 2017** | **December 31 2016** |
|---|---|---|
| Notes payable to the Ontario Electricity Financial Corporation | **3,245** | 3,295 |
| UMH Energy Partnership | **182** | 184 |
| PSS Generating Station Limited Partnership | **245** | 245 |
| Lower Mattagami Energy Limited Partnership | **1,795** | 1,795 |
| Other | **15** | 15 |
| | **5,482** | 5,534 |
| Less: bond issuance fees | **(14)** | (14) |
| Less: due within one year | **(628)** | (1,103) |
| Long-term debt | **4,840** | 4,417 |

In the fourth quarter of 2015, PSS Generating Station Limited Partnership (PSS), a subsidiary of OPG, issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. Generating Station (GS) project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at September 30, 2017, the deposit note had matured.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the Ontario Electricity Financial Corporation (OEFC), which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totaling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.

## 5. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. As at September 30, 2017, there were no amounts outstanding under the bank credit facility. There was $160 million commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, the Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program, and the issuance of the Letters of Credit. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million

was issued in July 2017 and remains outstanding as at September 30, 2017 under the first tranche of LME's credit facility.

As at September 30, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the Portlands Energy Centre (PEC), a jointly controlled entity in which OPG holds a 50 percent interest.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at September 30, 2017, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at September 30, 2017, total Letters of Credit of $14 million had been issued under these facilities.

The following table summarizes the net interest expense:

| | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| *(millions of dollars)* | **2017** | **2016** | **2017** | **2016** |
| Interest on long-term debt | **74** | 73 | **215** | 217 |
| Interest on short-term debt | **-** | - | **2** | 2 |
| Interest income | **(4)** | (1) | **(6)** | (5) |
| Interest capitalized to property, plant and equipment and intangible assets | **(39)** | (36) | **(121)** | (101) |
| Interest related to regulatory assets and liabilities [1] | **(10)** | (8) | **(34)** | (21) |
| Net interest expense | **21** | 28 | **56** | 92 |

[1] Includes interest to recognize the cost of financing related to regulatory variance and deferral accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

## 6. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at September 30, 2017 and December 31, 2016 consist of the following:

| *(millions of dollars)* | **September 30 2017** | **December 31 2016** |
|---|---|---|
| Liability for nuclear used fuel management | **11,690** | 11,292 |
| Liability for nuclear decommissioning and nuclear low and intermediate level waste management | **8,009** | 7,811 |
| Liability for non-nuclear fixed asset removal | **376** | 381 |
| Fixed asset removal and nuclear waste management liabilities | **20,075** | 19,484 |

## 7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), are as follows:

| | **Nine Months Ended September 30, 2017** | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Losses on Cash Flow Hedges [1]** | **Pension and OPEB [1]** | **Available-for-sale Securities [1]** | **Total [1]** |
| AOCL, beginning of period | **(87)** | **(207)** | **(1)** | **(295)** |
| Unrealized loss on available-for-sale securities | **-** | **-** | **(6)** | **(6)** |
| Amounts reclassified from AOCL | **13** | **8** | **-** | **21** |
| Other comprehensive income (loss) for the period | **13** | **8** | **(6)** | **15** |
| Reclassification of non-controlling interest on change in ownership interest *(Note 15)* | **3** | **-** | **-** | **3** |
| AOCL, end of period | **(71)** | **(199)** | **(7)** | **(277)** |

[1] All amounts are net of income taxes.

| | **Nine Months Ended September 30, 2016** | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Losses on Cash Flow Hedges [1]** | **Pension and OPEB [1]** | **Available-for-sale Securities [1]** | **Total [1]** |
| AOCL, beginning of period | (106) | (213) | - | (319) |
| Unrealized gain on available-for-sale securities | - | - | 15 | 15 |
| Amounts reclassified from AOCL | 14 | 9 | - | 23 |
| Other comprehensive income for the period | 14 | 9 | 15 | 38 |
| AOCL, end of period | (92) | (204) | 15 | (281) |

[1] All amounts are net of income taxes.

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2017 are as follows:

| *(millions of dollars)* | **Amount Reclassified from AOCL Three Months Ended September 30, 2017** | **Nine Months Ended September 30, 2017** | **Statement of Income Line Item** |
|---|---|---|---|
| Amortization of losses from cash flow hedges | | | |
| Losses | **5** | **15** | Net interest expense |
| Income tax recovery | **(1)** | **(2)** | Income tax expense |
| | **4** | **13** | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses | **3** | **10** | See (1) below |
| Income tax recovery | **-** | **(2)** | Income tax expense |
| | **3** | **8** | |
| Total reclassifications for the period | **7** | **21** | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine months ended September 30, 2016 are as follows:

| *(millions of dollars)* | **Amount Reclassified from AOCL Three Months Ended September 30, 2016** | **Nine Months Ended September 30, 2016** | **Statement of Income Line Item** |
|---|---|---|---|
| Amortization of losses from cash flow hedges | | | |
| Losses | 5 | 16 | Net interest expense |
| Income tax recovery | (1) | (2) | Income tax expense |
| | 4 | 14 | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses | 4 | 12 | See (1) below |
| Income tax recovery | (1) | (3) | Income tax expense |
| | 3 | 9 | |
| Total reclassifications for the period | 7 | 23 | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

## 8. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended September 30, 2017 and 2016 are as follows:

| | Registered Pension Plans | | Supplementary Pension Plans | | OPEB | |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| *Components of Cost Recognized for the period* | | | | | | |
| Current service costs | **68** | 70 | **2** | 2 | **17** | 16 |
| Interest on projected benefit obligation | **138** | 158 | **2** | 3 | **27** | 34 |
| Expected return on plan assets, net of expenses | **(191)** | (185) | **-** | - | **-** | - |
| Amortization of net actuarial loss [1] | **45** | 49 | **2** | 1 | **-** | 5 |
| Cost recognized [2] | **60** | 92 | **6** | 6 | **44** | 55 |

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $44 million (three months ended September 30, 2016 – $51 million).

[2] These pension and OPEB costs for the three months ended September 30, 2017 exclude the net addition of costs of $3 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended September 30, 2016 – net reduction of costs of $35 million).

OPG's pension and OPEB costs for the nine months ended September 30, 2017 and 2016 are as follows:

| | Registered Pension Plans | | Supplementary Pension Plans | | OPEB | |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| *Components of Cost Recognized for the period* | | | | | | |
| Current service costs | **205** | 208 | **5** | 5 | **51** | 50 |
| Interest on projected benefit obligation | **411** | 475 | **8** | 9 | **81** | 100 |
| Expected return on plan assets, net of expenses | **(574)** | (552) | **-** | - | **-** | - |
| Amortization of net actuarial loss [1] | **137** | 145 | **5** | 3 | **-** | 15 |
| Cost recognized [2] | **179** | 276 | **18** | 17 | **132** | 165 |

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the nine months ended September 30, 2017 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $132 million (nine months ended September 30, 2016 – $151 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2017 exclude the net addition of costs of $10 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (nine months ended September 30, 2016 − net reduction of costs of $107 million).

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018 and $219 million for 2019.

## 9. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at September 30, 2017 was less than $1 million. OPG's fair value derivatives totalled a net liability of $16 million as at September 30, 2017 (December 31, 2016 – $24 million).

Existing pre-tax net losses of $20 million deferred in AOCL as at September 30, 2017 are expected to be reclassified to net income within the next 12 months.

## 10. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

Certain alternative investments are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

Transfers into, out of, or between levels are deemed to have occurred on the date of the event or change in circumstances that caused the transfer to occur.

The following is a summary of OPG's financial instruments and their fair value as at September 30, 2017 and December 31, 2016:

| | Fair Value | | Carrying Value [1] | | |
|---|---|---|---|---|---|
| *(millions of dollars)* | **2017** | **2016** | **2017** | **2016** | **Balance Sheet Line Item** |
| Nuclear Segregated Funds (includes current portion) [2] | **16,534** | 15,984 | **16,534** | 15,984 | Nuclear fixed asset removal and nuclear waste management funds |
| Investment in Hydro One shares | **190** | 212 | **190** | 212 | Available-for-sale securities |
| Payable related to cash flow hedges | **(42)** | (48) | **(42)** | (48) | Long-term accounts payable and accrued charges |
| Long-term debt (includes current portion) | **(5,859)** | (6,033) | **(5,482)** | (5,520) | Long-term debt |
| Other financial instruments | **(11)** | (18) | **(11)** | (18) | Various |

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund.

The fair value of long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2017 and December 31, 2016:

| | September 30, 2017 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **5,879** | **4,498** | **-** | **10,377** |
| Investments measured at NAV [1] | | | | **1,231** |
| | | | | **11,608** |
| Due to Province | | | | **(2,155)** |
| Used Fuel Segregated Fund, net | | | | **9,453** |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **4,363** | **3,343** | **-** | **7,706** |
| Investments measured at NAV [1] | | | | **1,016** |
| | | | | **8,722** |
| Due to Province | | | | **(1,641)** |
| Decommissioning Segregated Fund, net | | | | **7,081** |
| Investment in available-for-sale securities [2] | **190** | **-** | **-** | **190** |
| Other financial assets | **4** | **3** | **7** | **14** |
| **Liabilities** | | | | |
| Other financial liabilities | **(22)** | **(3)** | **-** | **(25)** |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

| *(millions of dollars)* | December 31, 2016 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 5,602 | 4,394 | - | 9,996 |
| Investments measured at NAV [1] | | | | 1,086 |
| | | | | 11,082 |
| Due to Province | | | | (1,938) |
| Used Fuel Segregated Fund, net | | | | 9,144 |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 4,171 | 3,243 | - | 7,414 |
| Investments measured at NAV [1] | | | | 903 |
| | | | | 8,317 |
| Due to Province | | | | (1,477) |
| Decommissioning Segregated Fund, net | | | | 6,840 |
| Investment in available-for-sale securities | 212 | - | - | 212 |
| Other financial assets | 6 | 2 | 9 | 17 |
| **Liabilities** | | | | |
| Other financial liabilities | (29) | (6) | - | (35) |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the nine months ended September 30, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended September 30, 2017:

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, July 1, 2017 | **9** |
| Realized losses included in revenue | **(4)** |
| Purchases | **2** |
| Closing balance, September 30, 2017 | **7** |

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the nine months ended September 30, 2017:

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, January 1, 2017 | **9** |
| Unrealized losses included in revenue | **(2)** |
| Realized losses included in revenue | **(7)** |
| Purchases | **7** |
| Closing balance, September 30, 2017 | **7** |

## Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Alternative investments are measured at fair value using NAV as a practical expedient.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at September 30, 2017:

| *(millions of dollars except where noted)* | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice |
|---|---|---|---|---|
| Alternative Investments | | | | |
| Infrastructure | **1,276** | **835** | **n/a** | **n/a** |
| Real Estate | **892** | **465** | **n/a** | **n/a** |
| Agriculture | **78** | **106** | **n/a** | **n/a** |
| Pooled Funds | | | | |
| Short-term Investments | **12** | **n/a** | **Daily** | **1 - 5 Days** |
| Fixed Income | **643** | **n/a** | **Daily** | **1 - 5 Days** |
| Equity | **890** | **n/a** | **Daily** | **1 - 5 Days** |
| Total | **3,791** | **1,406** | | |

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This class includes investments in funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments such as energy, transportation and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in partners' capital and/or underlying investments held by subsidiaries of an infrastructure fund. The investments in the respective infrastructure funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments of the infrastructure funds are liquidated. It is not possible to estimate when the underlying assets of the infrastructure funds will be liquidated. However, the infrastructure funds have a maturity end period ranging from 2019 to 2025.

Real Estate

This class includes investments in institutional-grade real estate property. The investment objective is to provide a stable level of income with the opportunity for long-term capital appreciation. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The partnership investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this class will be liquidated.

Agriculture

This class includes a diversified portfolio of global farmland and timberland investments. The investment objective is to provide a differentiated return source, income yield, and inflation protection. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements.

Pooled Funds

This class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

## 11. COMMITMENTS AND CONTINGENCIES

### Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power L.P. (Bruce Power) by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set out in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

### Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at September 30, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these

guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at September 30, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

## Contractual and Commercial Commitments

OPG's contractual obligations and commercial commitments as at September 30, 2017 are as follows:

| *(millions of dollars)* | **2017** [1] | **2018** | **2019** | **2020** | **2021** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Fuel supply agreements | 52 | 169 | 96 | 76 | 62 | 98 | 553 |
| Contributions to the OPG registered pension plan [2] | 23 | 215 | 219 | - | - | - | 457 |
| Long-term debt repayment | 251 | 398 | 368 | 663 | 413 | 3,389 | 5,482 |
| Interest on long-term debt | 54 | 244 | 225 | 203 | 175 | 3,167 | 4,068 |
| Commitments related to Darlington Refurbishment [3] | 530 | - | - | - | - | - | 530 |
| Commitments related to Peter Sutherland Sr. GS project | 7 | 1 | - | - | - | - | 8 |
| Commitments related to Ranney Falls GS project | 9 | 29 | 5 | - | - | - | 43 |
| Operating licences | 10 | 40 | 41 | 24 | 28 | 115 | 258 |
| Operating lease obligations | 8 | 27 | 25 | 25 | 23 | 93 | 201 |
| Unconditional purchase obligations | 15 | 59 | 58 | 56 | 5 | - | 193 |
| Accounts payable and accrued charges | 844 | 8 | - | - | - | 16 | 868 |
| Other | 35 | 43 | 30 | 2 | 1 | 65 | 176 |
| Total | 1,838 | 1,233 | 1,067 | 1,049 | 707 | 6,943 | 12,837 |

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

## 12. BUSINESS SEGMENTS

| Segment Income (Loss) for the Three Months Ended September 30, 2017 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Manage-ment | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue | 739 | 33 | 327 | 141 | 9 | (32) | 1,217 |
| Fuel expense | 81 | - | 88 | 15 | 1 | - | 185 |
| Gross margin | 658 | 33 | 239 | 126 | 8 | (32) | 1,032 |
| Operations, maintenance and administration | 511 | 35 | 81 | 39 | 1 | (32) | 635 |
| Depreciation and amortization | 116 | - | 34 | 20 | 8 | - | 178 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 230 | - | 3 | 2 | - | 235 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (196) | - | - | - | - | (196) |
| Property taxes | 7 | - | 1 | - | - | - | 8 |
| Income from investments subject to significant influence | - | - | - | (11) | - | - | (11) |
| Other losses (gains) | 4 | - | 1 | - | (2) | - | 3 |
| Income (Loss) before interest and income taxes | 20 | (36) | 122 | 75 | (1) | - | 180 |

| Segment Income (Loss) for the Three Months Ended September 30, 2016 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Manage-ment | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue | 885 | 36 | 350 | 149 | 15 | (35) | 1,400 |
| Fuel expense | 79 | - | 88 | 19 | 1 | - | 187 |
| Gross margin | 806 | 36 | 262 | 130 | 14 | (35) | 1,213 |
| Operations, maintenance and administration | 521 | 38 | 87 | 44 | 11 | (35) | 666 |
| Depreciation and amortization | 230 | - | 56 | 19 | 8 | - | 313 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 228 | - | 2 | 2 | - | 232 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (248) | - | - | - | - | (248) |
| Property taxes | 6 | - | 1 | 1 | 4 | - | 12 |
| Income from investments subject to significant influence | - | - | - | (11) | - | - | (11) |
| Other losses (gains) | 2 | - | 1 | 1 | (3) | - | 1 |
| Income (Loss) before interest and income taxes | 47 | 18 | 117 | 74 | (8) | - | 248 |

| Segment Income (Loss) for the Nine Months Ended September 30, 2017 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Manage-ment | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue | **2,000** | **90** | **1,069** | **431** | **36** | **(87)** | **3,539** |
| Fuel expense | **217** | **-** | **258** | **42** | **1** | **-** | **518** |
| Gross margin | **1,783** | **90** | **811** | **389** | **35** | **(87)** | **3,021** |
| Operations, maintenance and administration | **1,693** | **96** | **232** | **118** | **2** | **(87)** | **2,054** |
| Depreciation and amortization | **333** | **-** | **103** | **59** | **22** | **-** | **517** |
| Accretion on fixed asset removal and nuclear waste management liabilities | **-** | **696** | **-** | **7** | **6** | **-** | **709** |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **-** | **(579)** | **-** | **-** | **-** | **-** | **(579)** |
| Property taxes | **20** | **-** | **1** | **5** | **4** | **-** | **30** |
| Income from investments subject to significant influence | **-** | **-** | **-** | **(29)** | **-** | **-** | **(29)** |
| Other losses (gains) | **4** | **-** | **1** | **-** | **(385)** | **-** | **(380)** |
| (Loss) Income before interest and income taxes | **(267)** | **(123)** | **474** | **229** | **386** | **-** | **699** |

| Segment Income (Loss) for the Nine Months Ended September 30, 2016 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Manage-ment | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue | 2,631 | 102 | 1,148 | 431 | 52 | (99) | 4,265 |
| Fuel expense | 239 | - | 259 | 42 | 1 | - | 541 |
| Gross margin | 2,392 | 102 | 889 | 389 | 51 | (99) | 3,724 |
| Operations, maintenance and administration | 1,665 | 108 | 238 | 129 | 20 | (99) | 2,061 |
| Depreciation and amortization | 691 | - | 169 | 56 | 25 | - | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 684 | - | 6 | 6 | - | 696 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (620) | - | - | - | - | (620) |
| Property taxes | 19 | - | 1 | 6 | 9 | - | 35 |
| Income from investments subject to significant influence | - | - | - | (28) | - | - | (28) |
| Other (gains) losses | - | - | (19) | 1 | (5) | - | (23) |
| Income (Loss) before interest and income taxes | 17 | (70) | 500 | 219 | (4) | - | 662 |

Shareholder Declaration and Shareholder Resolution to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution that required the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. In December 2016, a purchase and sale agreement was executed, and the sale was completed in April 2017. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction for the nine months ended September 30, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the interim consolidated statement of income in the Services, Trading and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG is working to finalize the amount of designated proceeds to be transferred into the Province's Consolidated Revenue Fund.

## 13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

| *(millions of dollars)* | Nine Months Ended September 30 2017 | 2016 |
|---|---|---|
| Receivables from related parties | **72** | 107 |
| Prepaid expenses | **(18)** | (52) |
| Other current assets | **10** | (7) |
| Fuel inventory | **20** | 41 |
| Income taxes (recoverable)/ payable | **(92)** | 49 |
| Materials and supplies | **4** | (2) |
| Accounts payable and accrued charges | **(51)** | (195) |
| | **(55)** | (59) |

## 14. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of the PEC gas-fired combined cycle generating station and the Brighton Beach gas-fired combined cycle generating station (Brighton Beach), which are accounted for using the equity method. Details of the balances as at September 30, 2017 and December 31, 2016 are as follows:

| *(millions of dollars)* | September 30 2017 | December 31 2016 |
|---|---|---|
| **PEC** | | |
| Current assets | **19** | 18 |
| Long-term assets | **244** | 256 |
| Current liabilities | **(9)** | (8) |
| Long-term liabilities | **(5)** | (5) |
| **Brighton Beach** | | |
| Current assets | **5** | 5 |
| Long-term assets | **162** | 168 |
| Current liabilities | **(17)** | (16) |
| Long-term liabilities | **(8)** | (7) |
| Long-term debt | **(78)** | (90) |
| Investments subject to significant influence | **313** | 321 |

## 15. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.). The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. As a result of the contributions made by OPG and CRP, PSS has met the criteria of having sufficient equity at risk to finance its activities, and ceased being classified as a variable interest entity during the second quarter of 2017. OPG continues to consolidate the results of PSS in its consolidated financial statements. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit were proportionately allocated to CRP as a reduction to its non-controlling interest.

Ontario

MINISTRY OF
ENERGY

# Ontario Power Generation 2018-2021 Business Plan

March 2018

# Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

# Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

# Overview

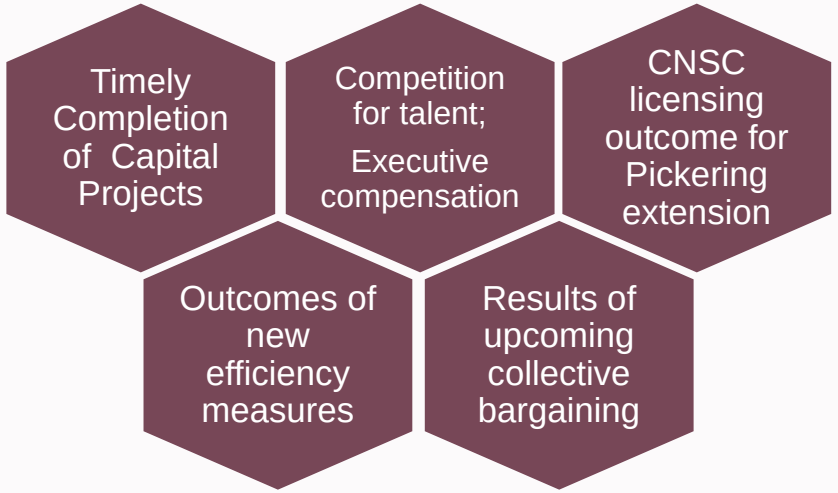
## Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:




## Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:




***OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.***

# Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

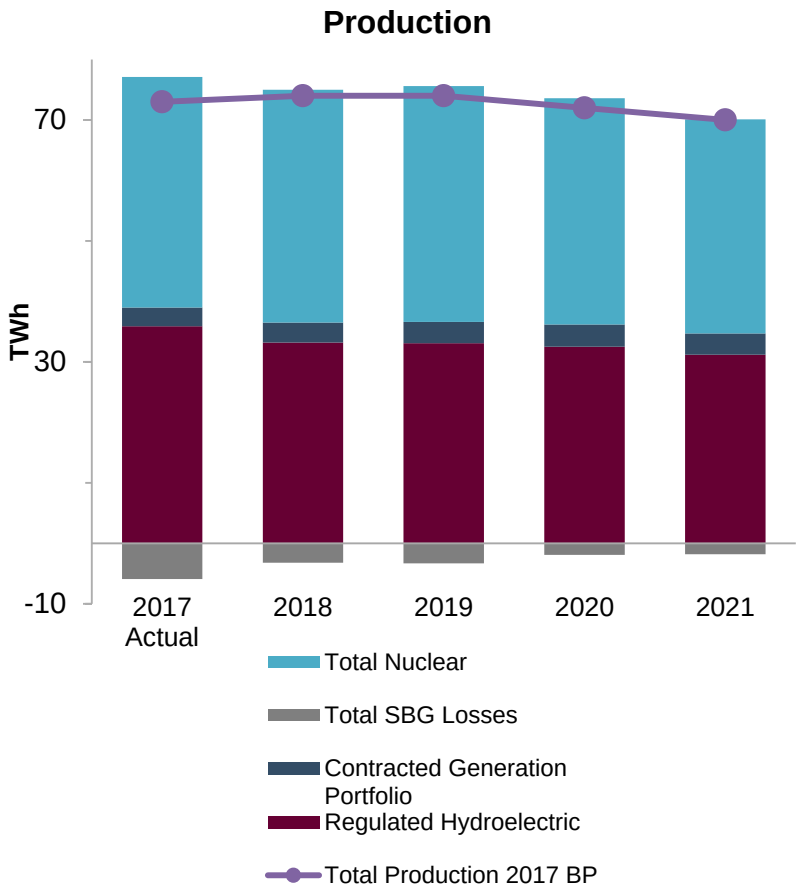
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

# Electricity Production

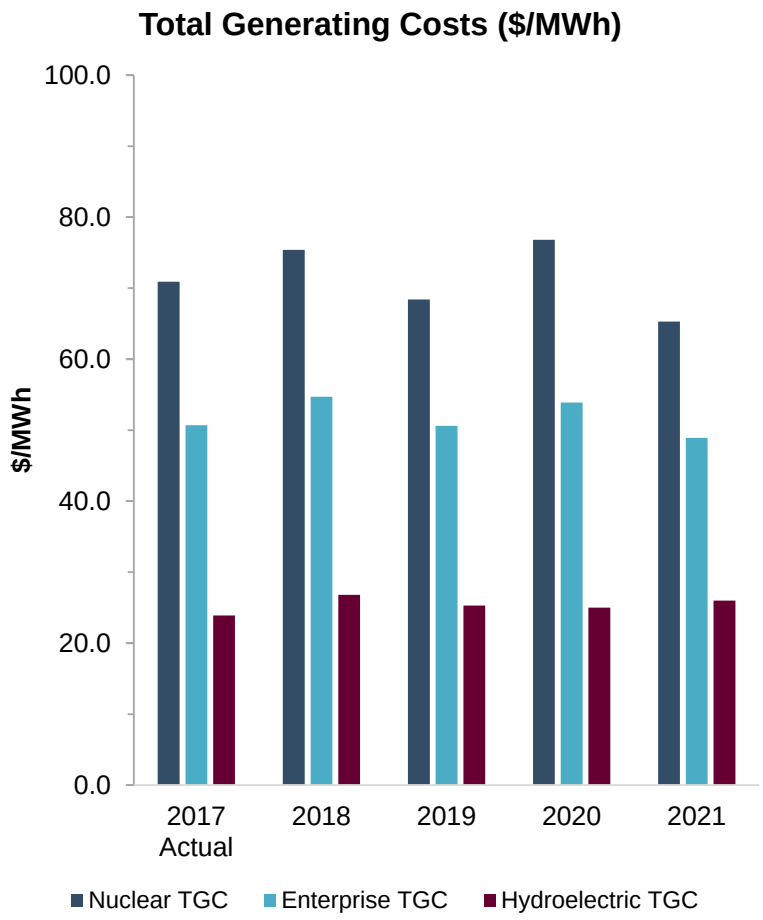
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering license extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction



# Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



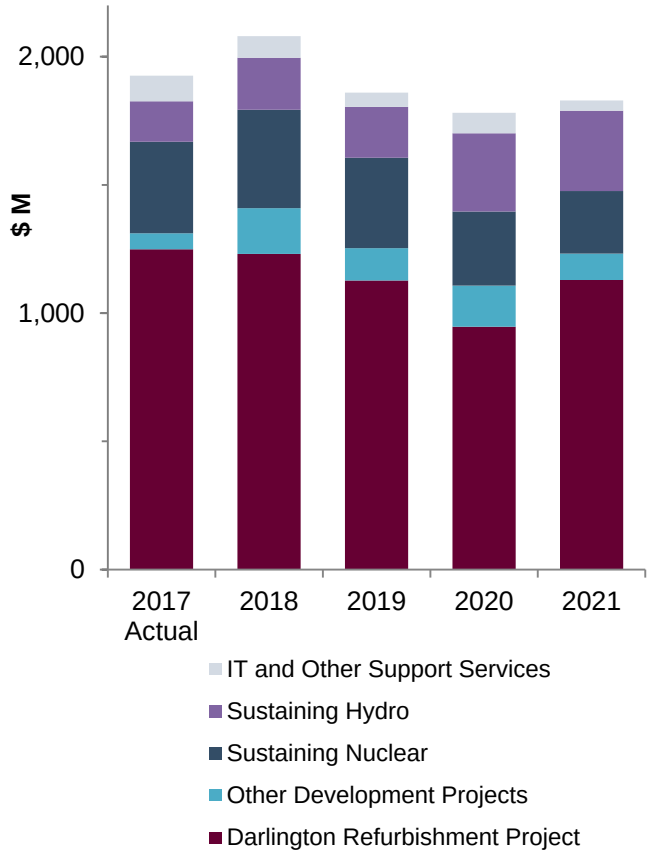

- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

# Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

**Total Capital Expenditures**



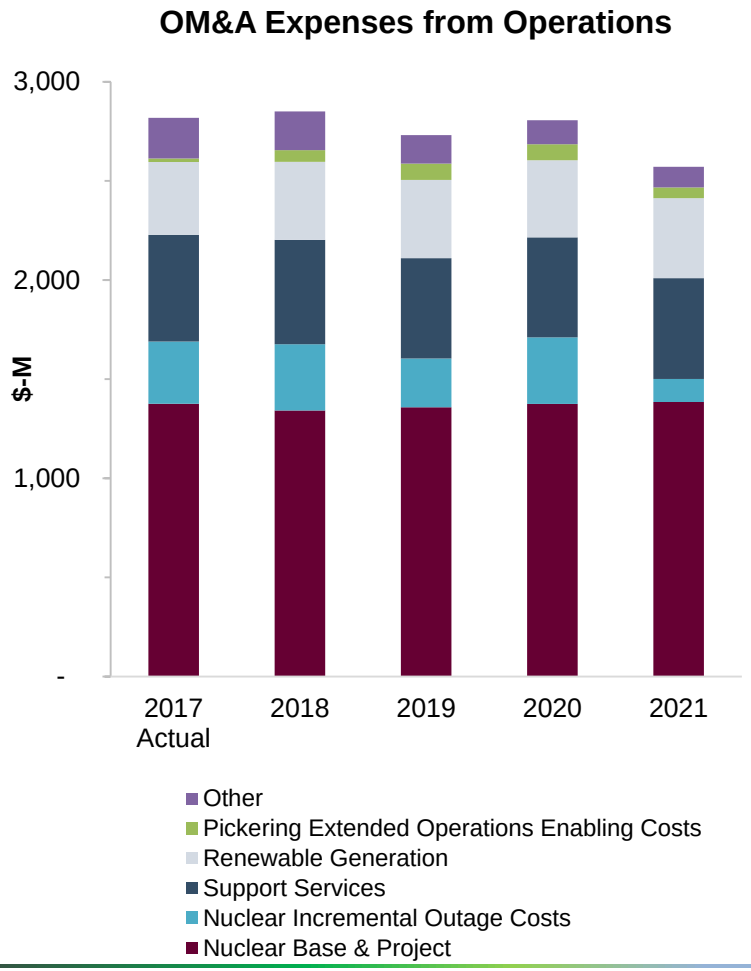
# Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

**OPG25 Initiative**

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

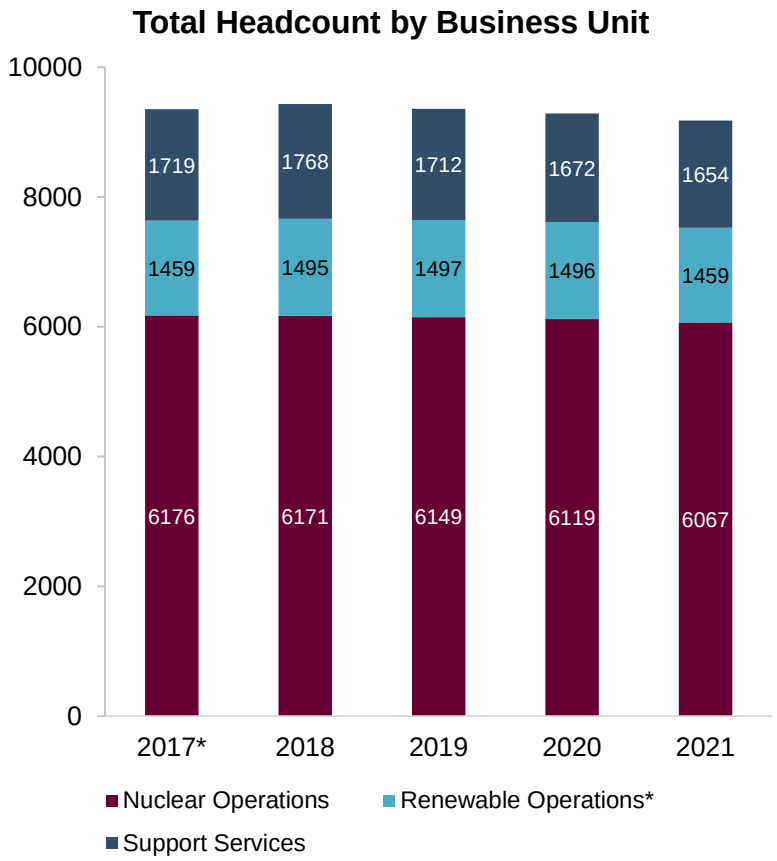


# Compensation

## *Collective Bargaining*

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



# Compensation

## *Executive Compensation*

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

**2016-2018 executive medium-term incentive performance metrics**
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

**Social License**: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

**Financial Strength**: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

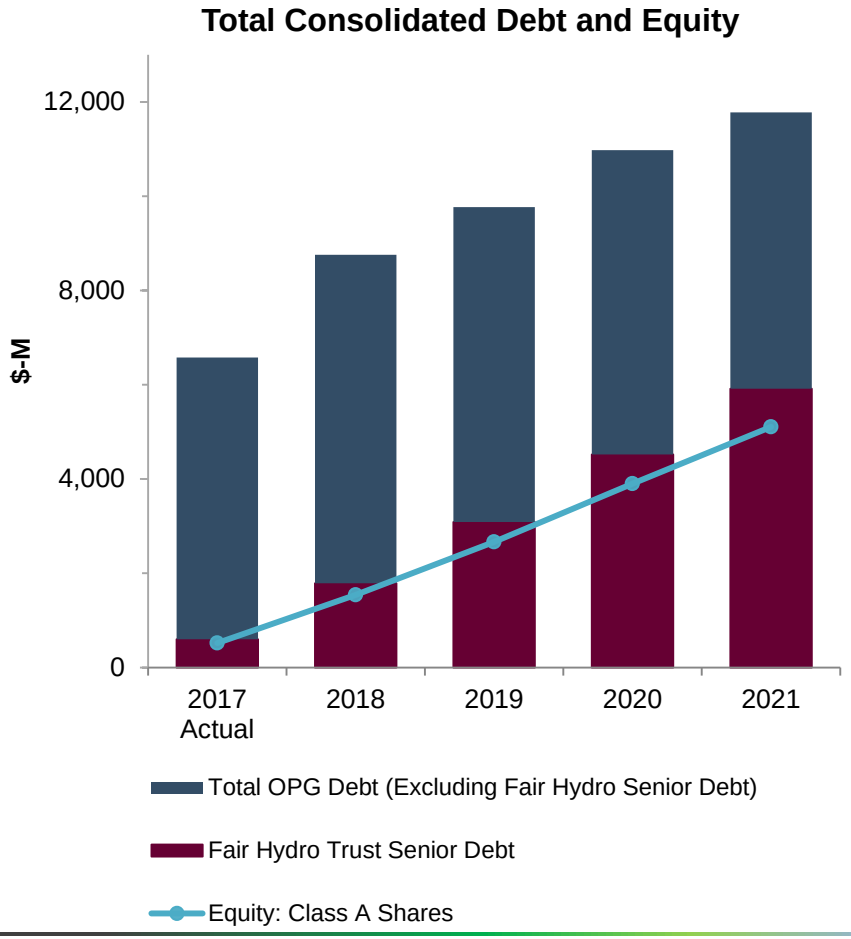
**Operational Excellence**: Total OPG production adjusted for Surplus Baseload Generation

**Project Excellence**: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

# Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



# Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

**Business Development investment categories:**

**Innovation & Services**
*OPG will consider investing in near commercial emerging technologies*

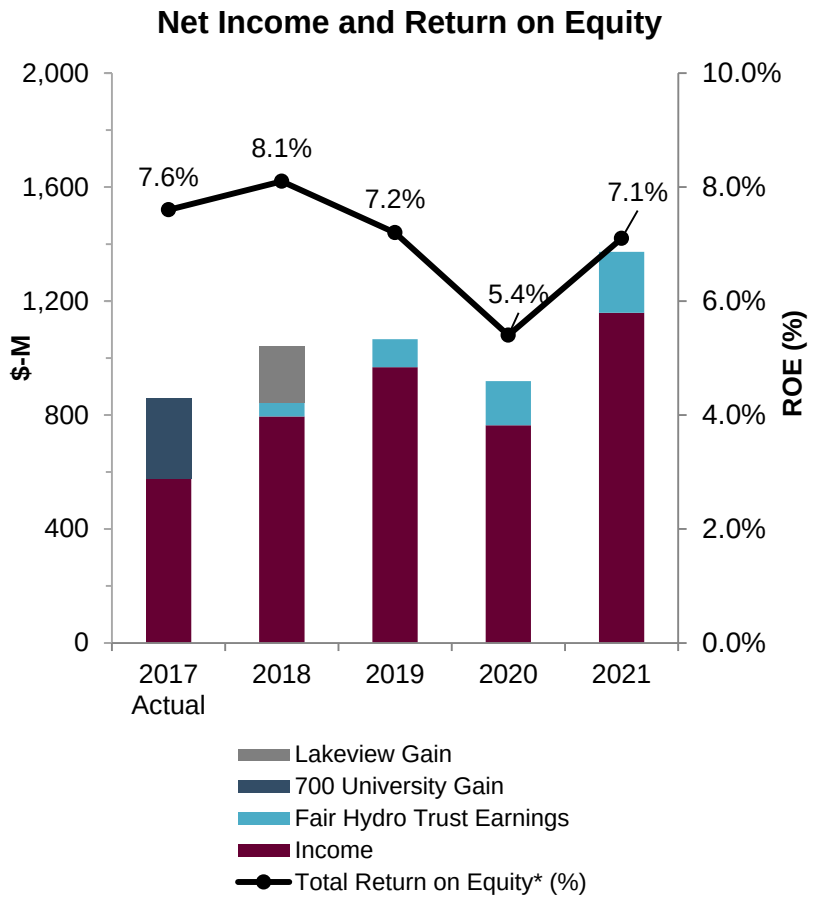
**Acquisition and Development**
*OPG will develop assets and consider acquisitions in Ontario and other North American markets*

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

# Financial Performance

*Business Plan Results as presented by OPG*

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.




- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), which will be credited to the Trillium Trust.

# Financial Performance

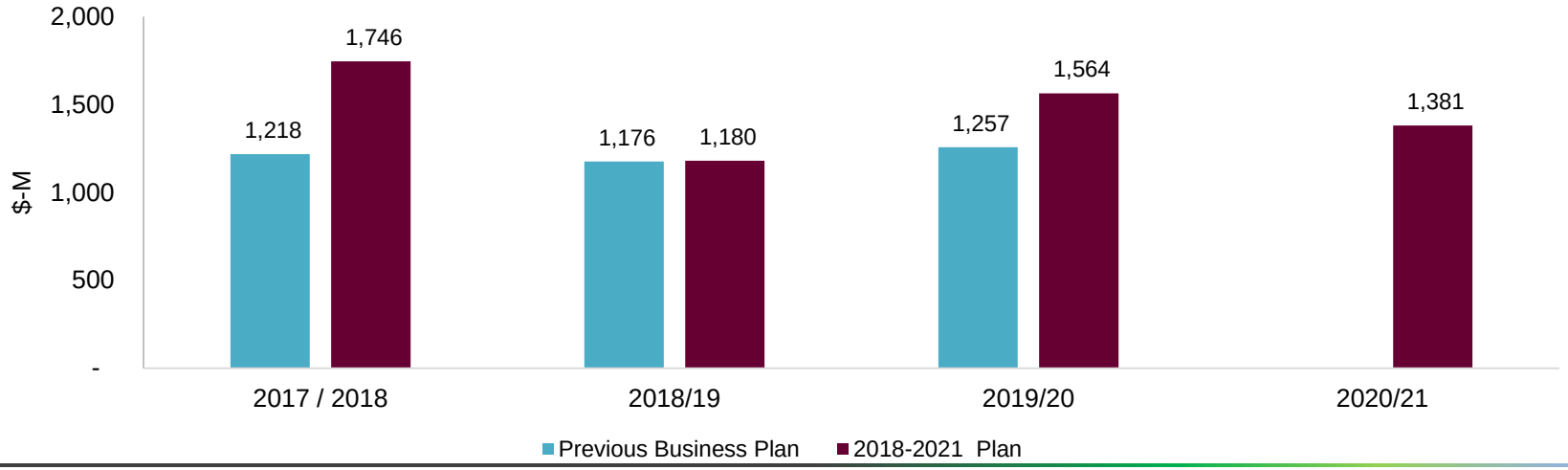
*2018-21 Business Plan compared to previous plan*

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG has a purchase agreement for Lakeview site, anticipated to close in March, 2018.

**Total Shareholder Return**

*2018-21 BP vs. Previous Business Plan*



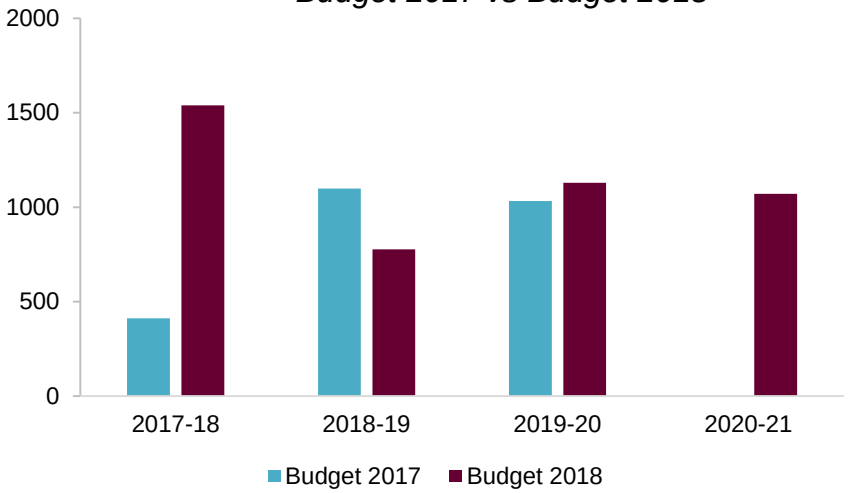
# Financial Performance:[OFA to review]

*Impacts to Province*

- The Ministry of Finance and Treasury Board Secretariat are responsible for the fiscal consolidation of OPG's financials on the Province's financial statements which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's financials are consolidated into the Province's financials, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results using International Financial Reporting Standards (IFRS).
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

***Total OPG Revenues to the Province***
*Budget 2017 vs Budget 2018*




2017/18 positive variance due to:
- $646M for real estate sales included in Budget 2018, not in Budget 2017.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

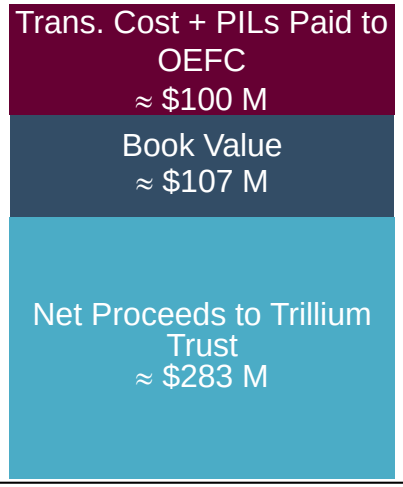
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

# Financial Performance

*Contribution to the Trillium Trust*

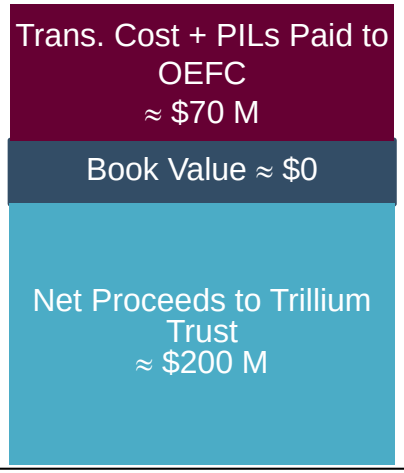
- Net proceeds from the sale of OPG's its Head Office (700 University) and Lakeview site are paid to the CRF and credited to the Trillium Trust.
- The Province will receive a dividend payment from OPG for the gains on these sales.
- The Head Office sale closed in April 2017. Lakeview expected to close in 2018.

**Head Office: Designated Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

**Lakeview: Estimated Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: June 2016
- Expected sale: March 2018
- Regulation required to prescribe amounts to Trillium trust

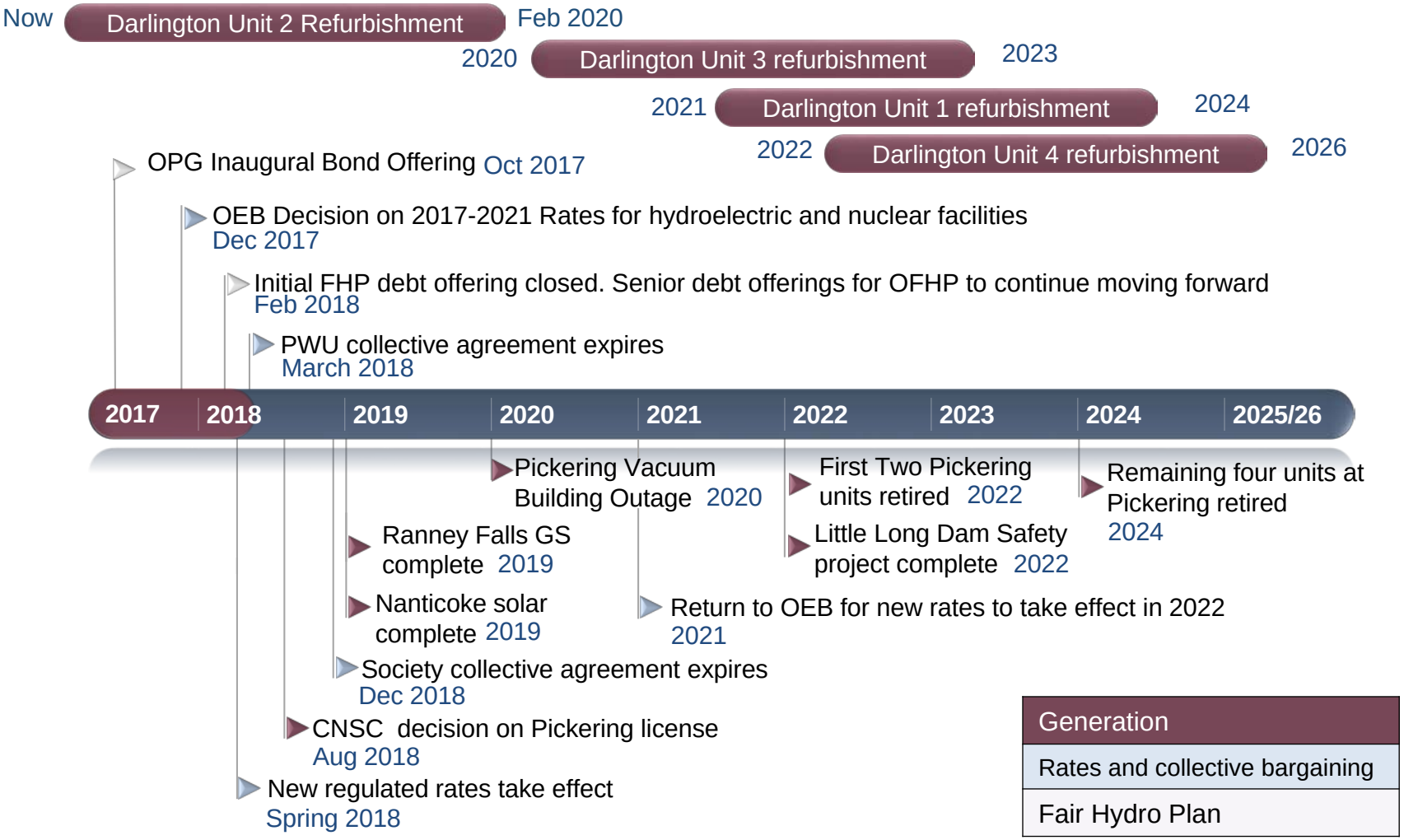
# Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

# Appendix

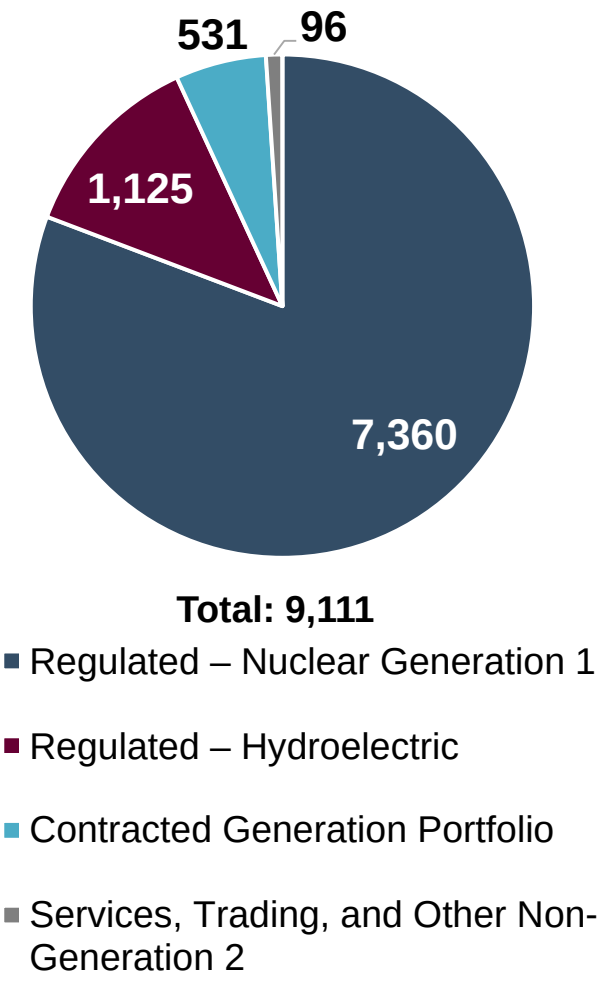
# Timeline

- Outcomes from the Business Plan are impacted by the following events:



# Company Profile

## 2017 Average Full-Time Employees

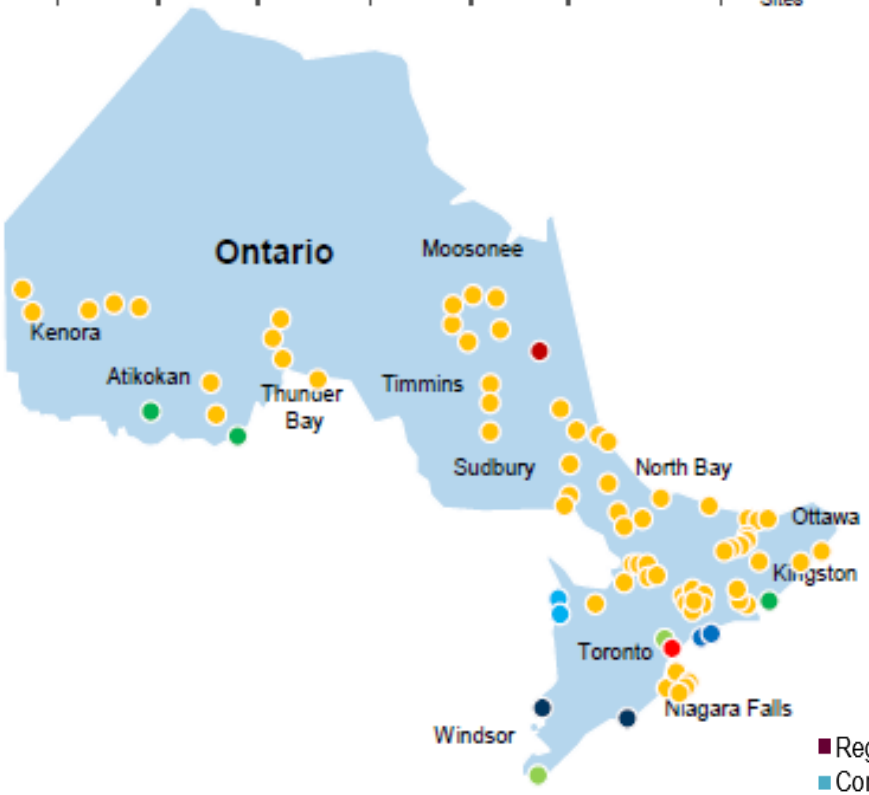


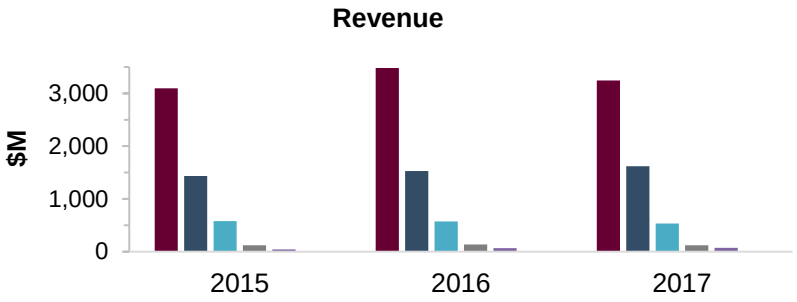

- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

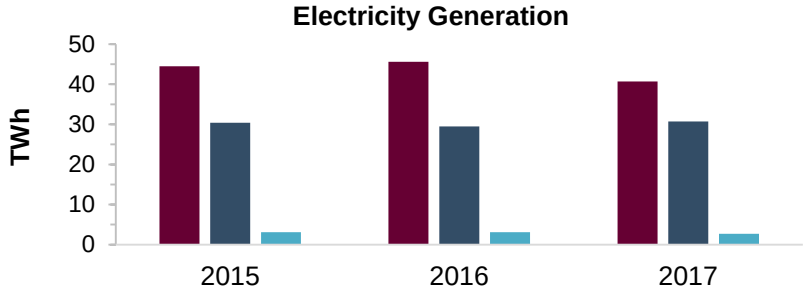
# Company Profile

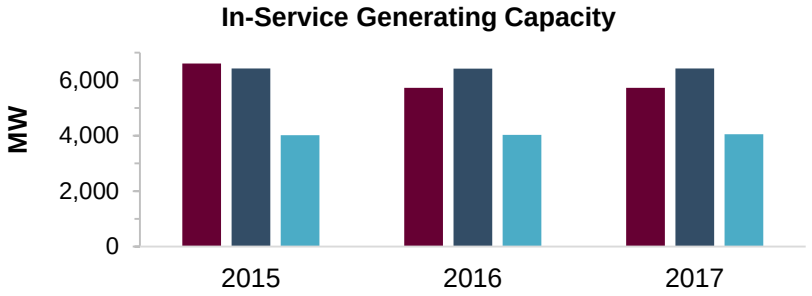
## Map of OPG Generating Stations:

| 2 | 2 | 3 | 2 | 65 | 1 | 1 | 2 |
|---|---|---|---|---|---|---|---|
| Nuclear Stations | Leased Nuclear Stations | Thermal Stations | Co-Owned Gas-Fired Stations | Hydro-electric Stations | Wind Power Turbine | Hydroelectric Project Under Construction [1] | Brownfield Coal Generation Sites |




- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

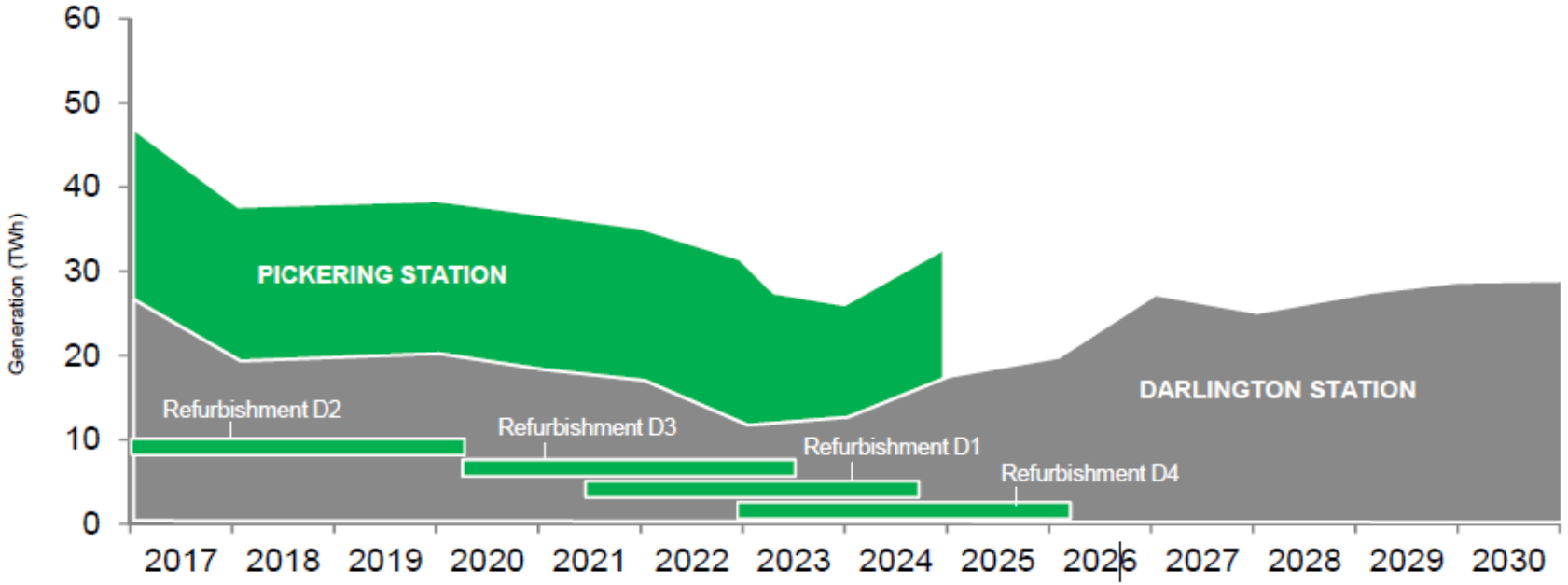
# Key Projects: Nuclear

### 1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

### 2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.




*Source: OPG Initial Public Debt Program, 2017*

# Key Projects: Renewables

## Biomass

**1. Atikokan**

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

**2. Thunder Bay**

Capacity: 153 MW

Converted from coal in 2014

## Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

## Hydroelectric

**1. Peter Sutherland Sr.**

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

**2. Lower Mattagami**

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

## Solar

**1. Nanticoke Solar**

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

# Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

# Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

| Director | Role | Appointed |
|---|---|---|
| 1. Bernard Lord | Chair | November 2013 |
| 2. Jeffrey Lyash | President and CEO of OPG | August 2015 |
| 3. William Coley | Director | January 2013 |
| 4. Elisabeth DeMarco | Director | April 2014 |
| 5. Jean Paul Gladu | Director | November 2015 |
| 6. John Herron | Director | November 2013 |
| 7. Ani Hotoyan-Joly | Director | March 2017 |
| 8. Wendy Kei | Director | March 2017 |
| 9. M. George Lewis | Director | February 2005 |
| 10. Margaret Mulligan | Director | December 2005 |
| 11. Yezdi Pavri | Director | September 2015 |
| 12. Gerry Phillips | Director | January 2013 |
| 13. Jim Reinsch | Director | August 2015 |
| 14. James Sheppard | Director | March 2017 |

# Compensation

## *2017 Statement of Executive Compensation*

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

| Category | **Performance Measure** | **Threshold Target** | **Business Plan Target** | **Stretch Target** | **2017 Results** | **Score (0 to 1.5)** |
|---|---|---|---|---|---|---|
| Social Licence | All Injury rate (AIR) | 0.49 | 0.37 | 0.31 | 0.48 | 0.54 |
| | Addressing Safety Focus Areas | CEO assessed target | | | 1.5 | 1.46 |
| | No significant impacts to OPG's reputation | | | | | |
| Financial Strength | Earnings Before Taxes, ($M) | 675 | 875 | 1075 | 1296 | 1.50 |
| | OM&A Expenses ($M) | 2675 | 2550 | 2425 | 2474 | 1.30 |
| Operational Excellence | Production (TWh) | 70.3 | 72.4 | 74.6 | 78.1 | 1.50 |
| Project Excellence | Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget | 100% | 97.50% | 95% | 120% | 0.00 |
| | Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone | 05-Aug-17 | 26-Jul-17 | 28-Jun-17 | 22-Jun-17 | 1.50 |
| | Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017 | All Bellows Severed | 50% End Fitting Removed | 400 Pressure Tubes Removed | 45% of End Fittings Removed | 0.95 |
| | Pump Generating Station: In service | 06-01-2017 | 04-01-2017 | 03-01-2017 | 02-04-2017 | 1.50 |
| | Peter Sutherland Generating Station: Both Units in service | 10-19-2017 | 06-30-2017 | 04-30-2017 | 03-31-2017 | 1.50 |
| | Total In-service Capital - | $578 (+/- 10% to +/- to 15%) | $578 (+/- 3% to +/- 10%) | $578 (to +/- 3%) | $625 (+8%) | 1.00 |
| | **Total Weighted Score[1]** | | | | | **1.19** |

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

Ontario

MINISTRY OF
ENERGY

# Ontario Power Generation 2018-2021 Business Plan

March 2018

# Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

# Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

# Overview

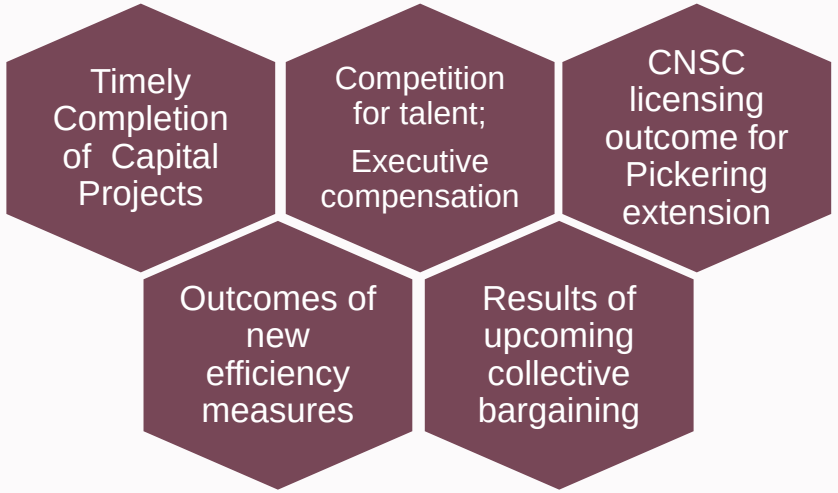
## Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:




## Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:




***OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.***

# Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

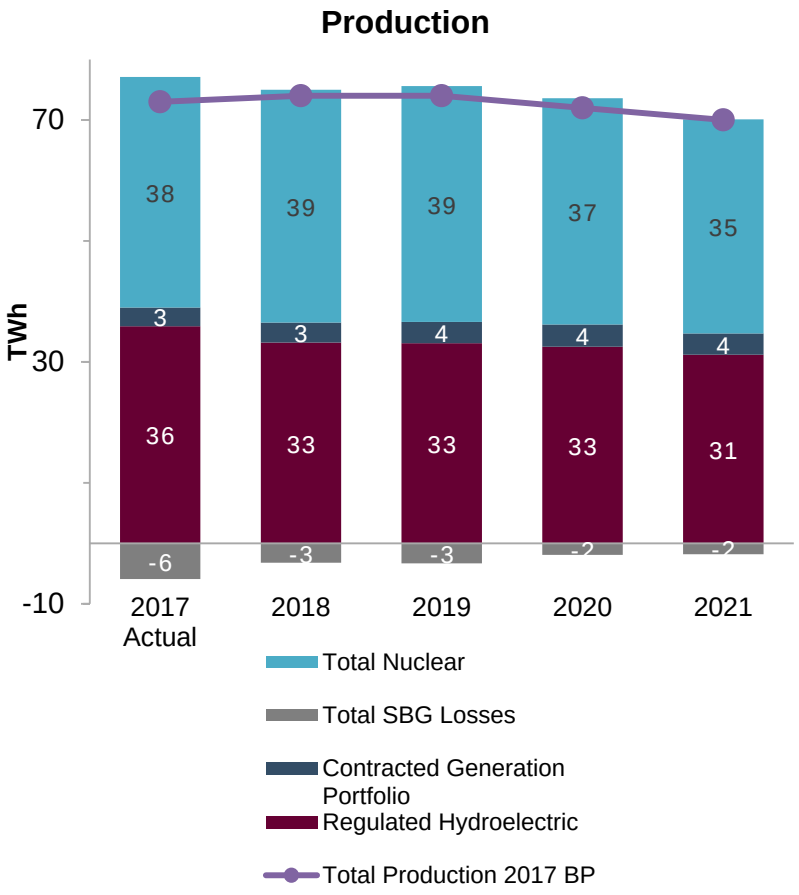
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

# Electricity Production

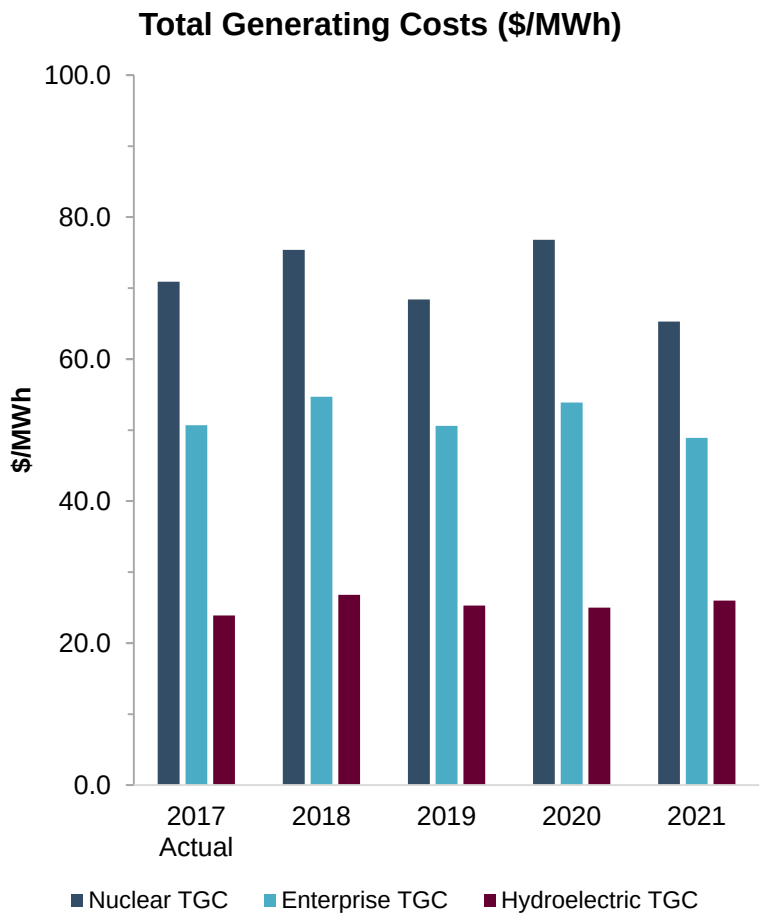
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering licence extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction.



# Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



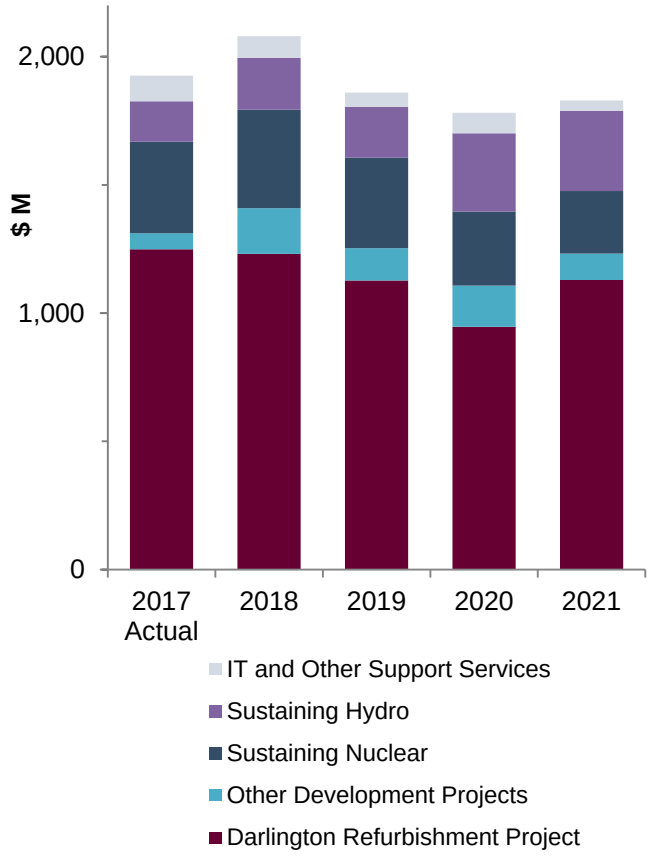

- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

# Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

**Total Capital Expenditures**



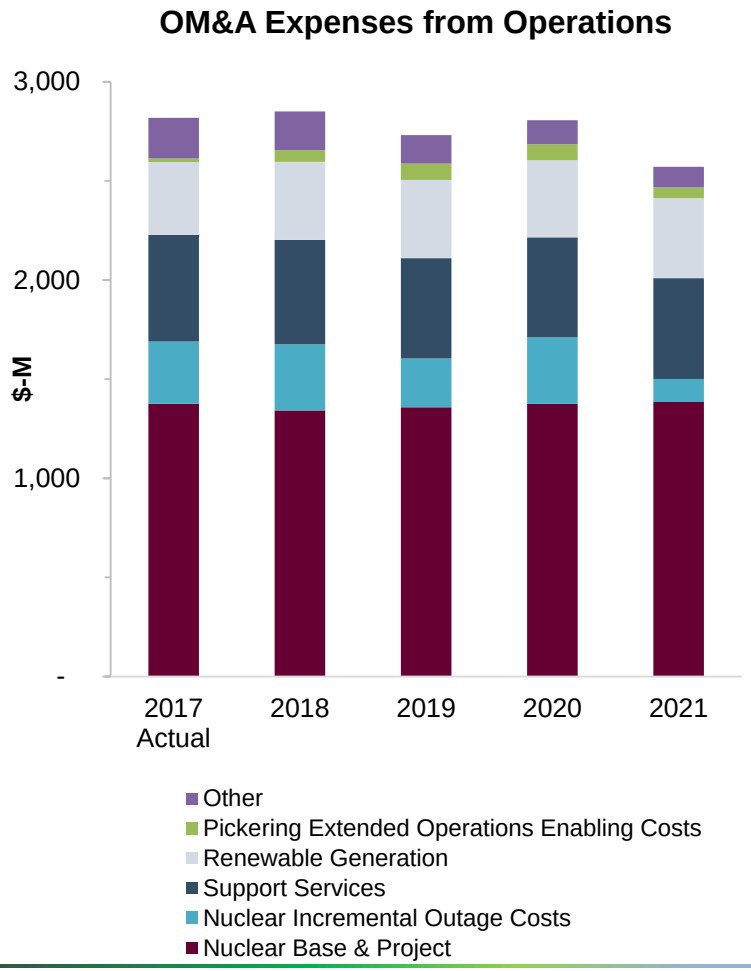
# Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

**OPG25 Initiative**

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

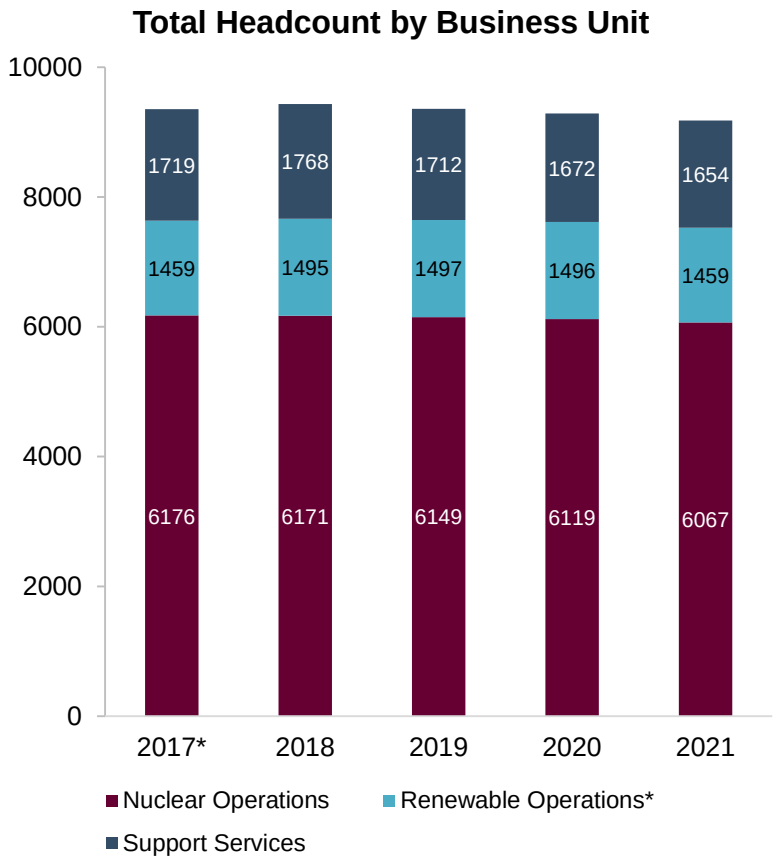


# Compensation

## *Collective Bargaining*

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



# Compensation

## *Executive Compensation*

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

**2016-2018 executive medium-term incentive performance metrics**
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

**Social Licence**: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

**Financial Strength**: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

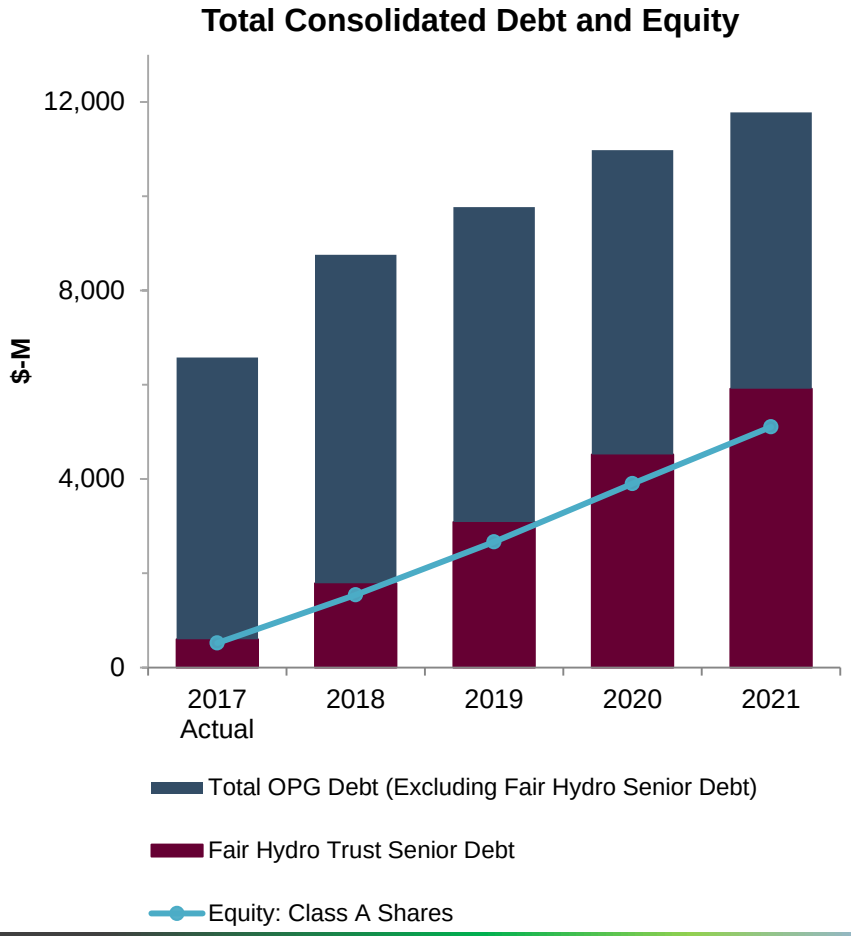
**Operational Excellence**: Total OPG production adjusted for Surplus Baseload Generation

**Project Excellence**: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

# Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



# Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

**Business Development investment categories:**

**Innovation & Services**
*OPG will consider investing in near commercial emerging technologies*

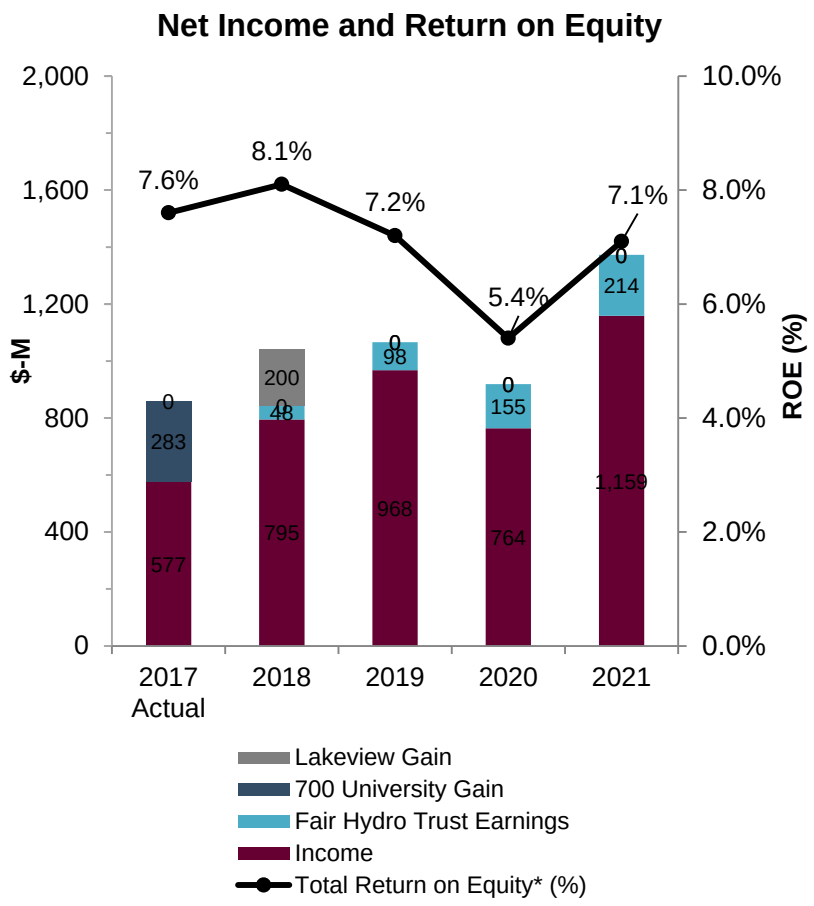
**Acquisition and Development**
*OPG will develop assets and consider acquisitions in Ontario and other North American markets*

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

# Financial Performance

*Business Plan Results as presented by OPG*

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.




- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), ~~which~~ with net proceeds ~~will be~~ credited to the Trillium Trust.

# Financial Performance

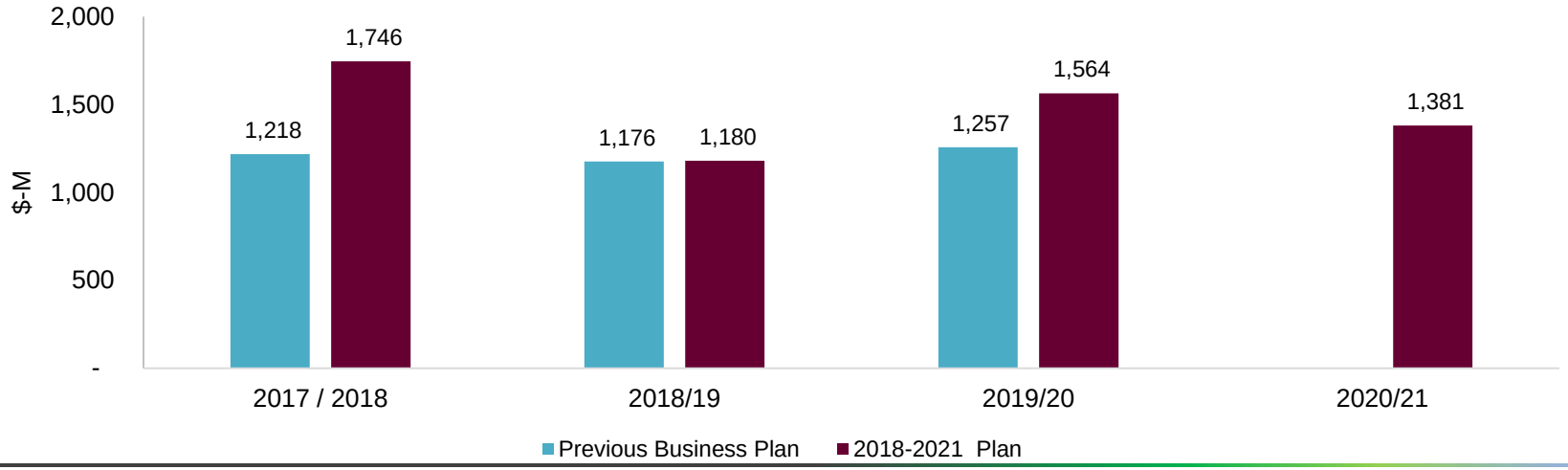
*2018-21 Business Plan compared to previous plan*

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG closed the sale of the ~~has a purchase agreement for~~ Lakeview site~~, anticipated to close~~ in March, 2018.

**Total Shareholder Return**

*2018-21 BP vs. Previous Business Plan*



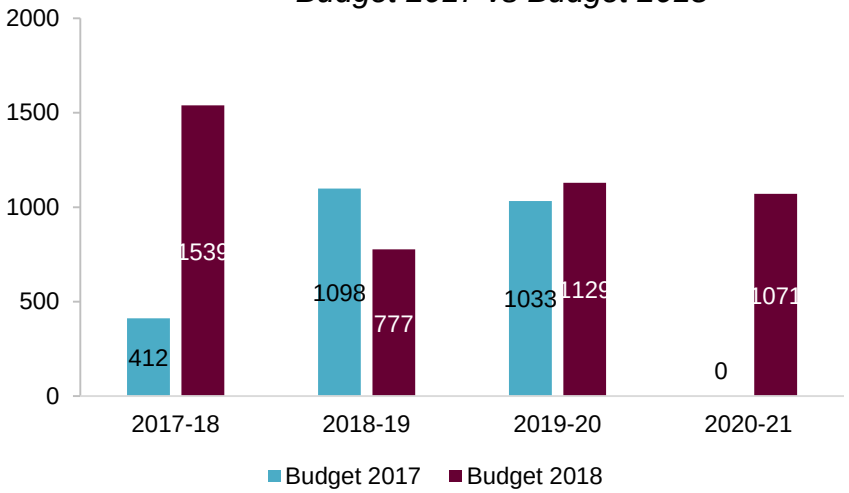
# Financial Performance:[OFA to review]

*Impacts to Province*

- The Ministry of Finance is responsible for incorporating OPG's financial projections into the Province's Fiscal Plan and fiscal plan updates, and Treasury Board Secretariat is responsible for the fiscal consolidation of OPG's financials on the Province's financial statements, which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's planning projections and financial results are consolidated into the Province's Budget and Public Accounts ~~financials~~, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results adjusted to an International Financial Reporting Standards (IFRS) basis.
  - **Nuclear Funds:** For the operating statement for Public Accounts, an adjustment is made to a realised gains basis, vs a fair value basis on OPG's statements.
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

***Total OPG Revenues to the Province***
*Budget 2017 vs Budget 2018*




2017/18 positive variance due to:
- $646M for real estate sales included as OPG revenue in Budget 2018,. In Budget 2017, ~~not in Budget 2017 as~~ projected OPG real estate revenues ~~those revenues~~ were included in the Sales and Rentals line.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

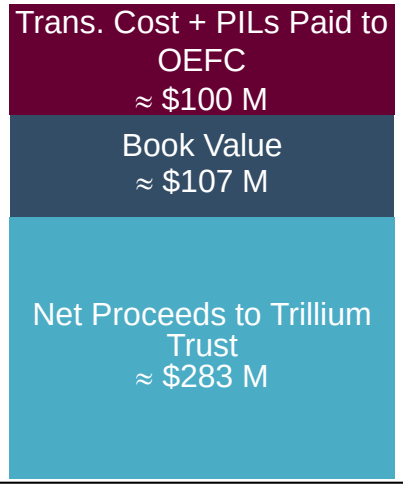
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

# Financial Performance

*Contribution to the Trillium Trust*

- Net proceeds from the sale of OPG's ~~its~~ Head Office (700 University) and Lakeview site are paid by OPG to the CRF and credited to the Trillium Trust.
- The Province ~~will~~ has received a dividend payment from OPG for the OPG Head Office Sale. OPG will be required to pay the net proceeds from the Lakeview sale once a Trillium Trust regulation is filed.~~gains on these sales.~~
- The Head Office sale closed in April 2017. Lakeview ~~expected to~~ closed in March, 2018.

**Head Office: ~~Designated~~ Net Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

**Lakeview: Estimated Net Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: June 2016
- ~~Expected~~ Sale closed: March 2018
- Regulation required to prescribe amounts to Trillium trust

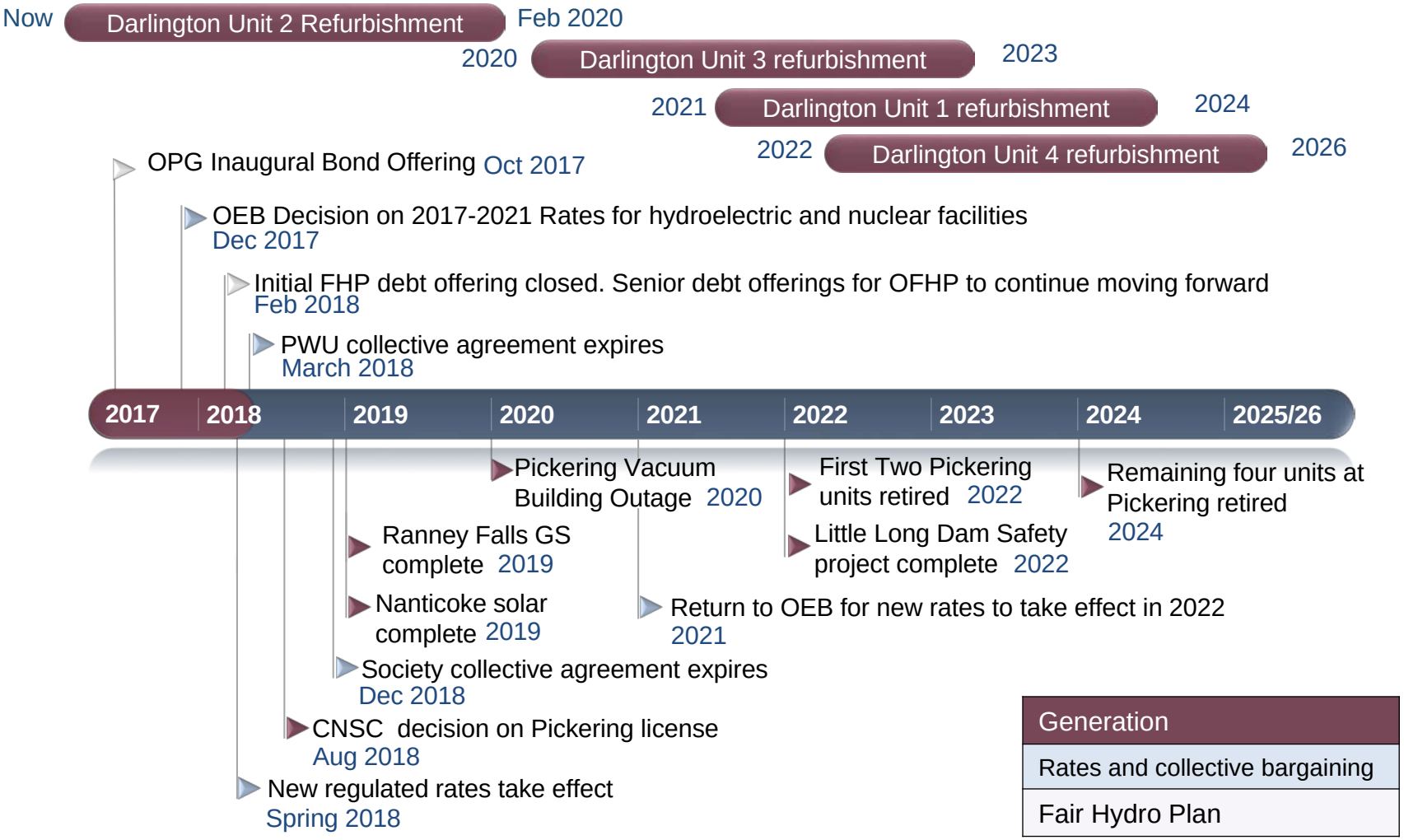
# Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

# Appendix

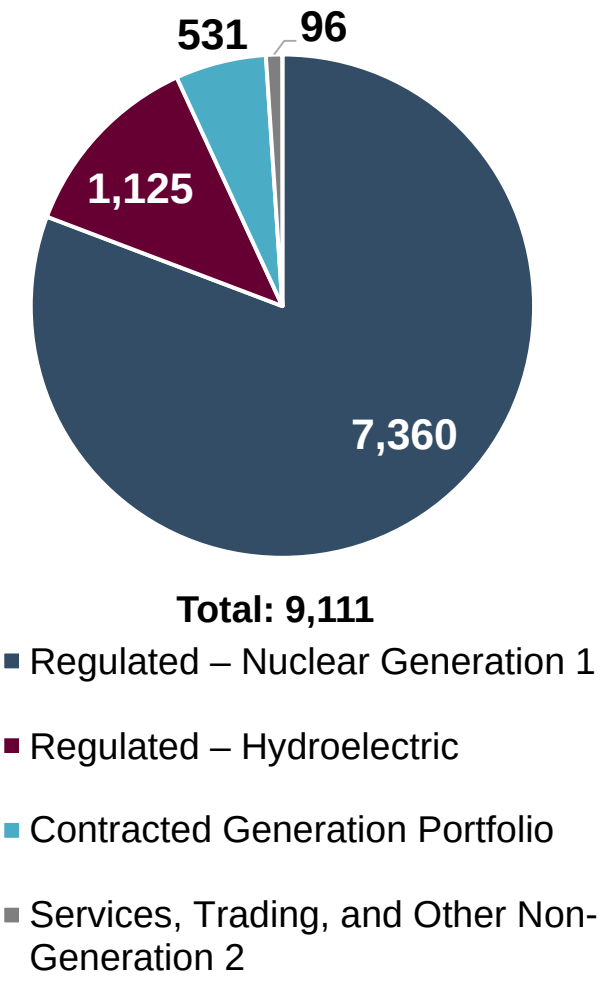
# Timeline

- Outcomes from the Business Plan are impacted by the following events:



# Company Profile

## 2017 Average Full-Time Employees

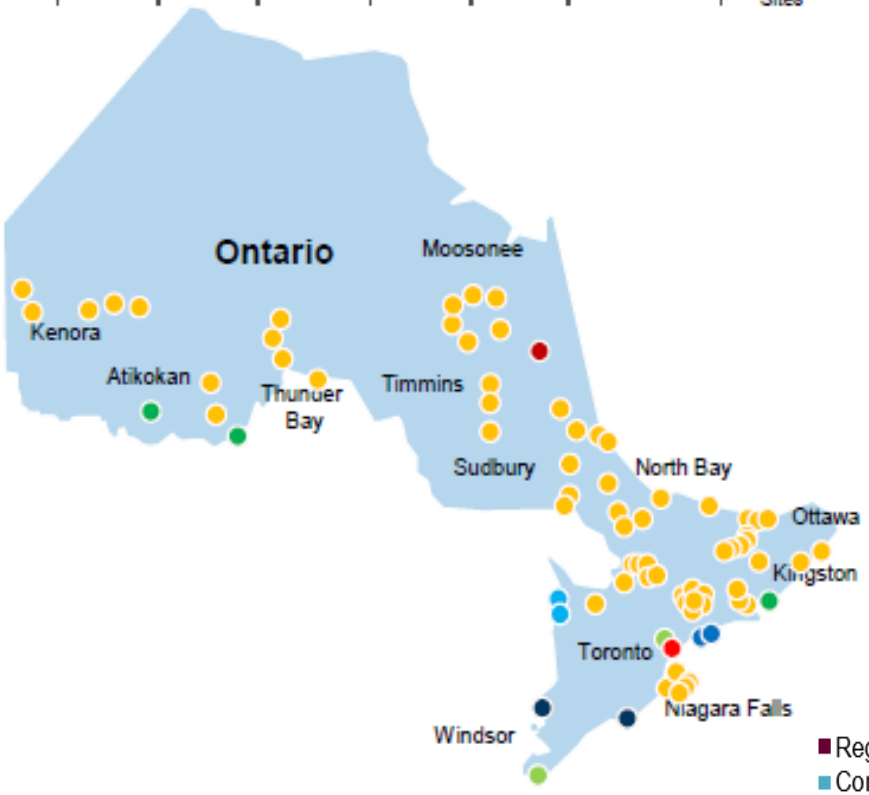


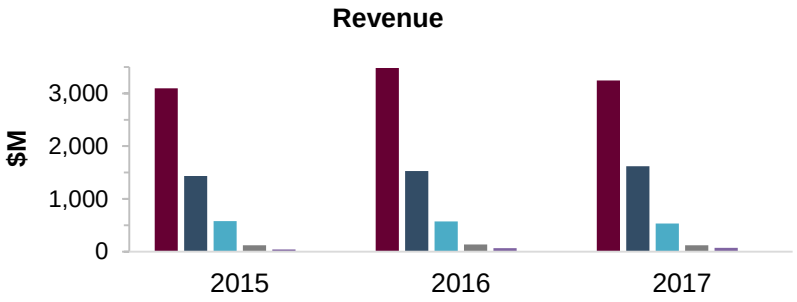

- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

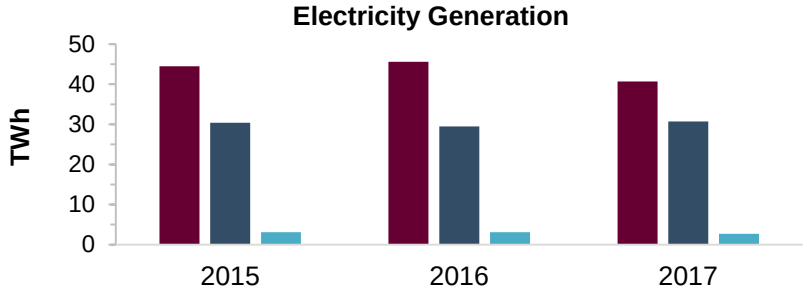
# Company Profile

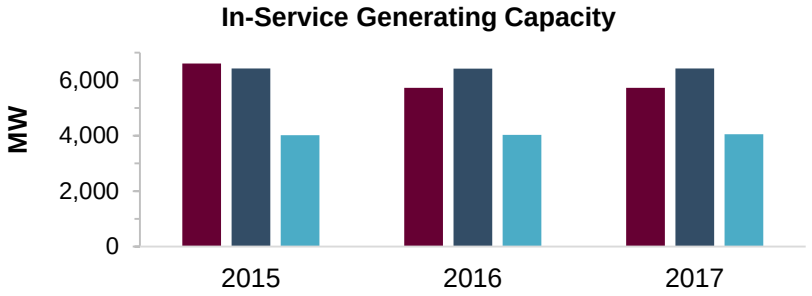
## Map of OPG Generating Stations:

| 2 | 2 | 3 | 2 | 65 | 1 | 1 | 2 |
|---|---|---|---|---|---|---|---|
| Nuclear Stations | Leased Nuclear Stations | Thermal Stations | Co-Owned Gas-Fired Stations | Hydro-electric Stations | Wind Power Turbine | Hydroelectric Project Under Construction [1] | Brownfield Coal Generation Sites |




- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

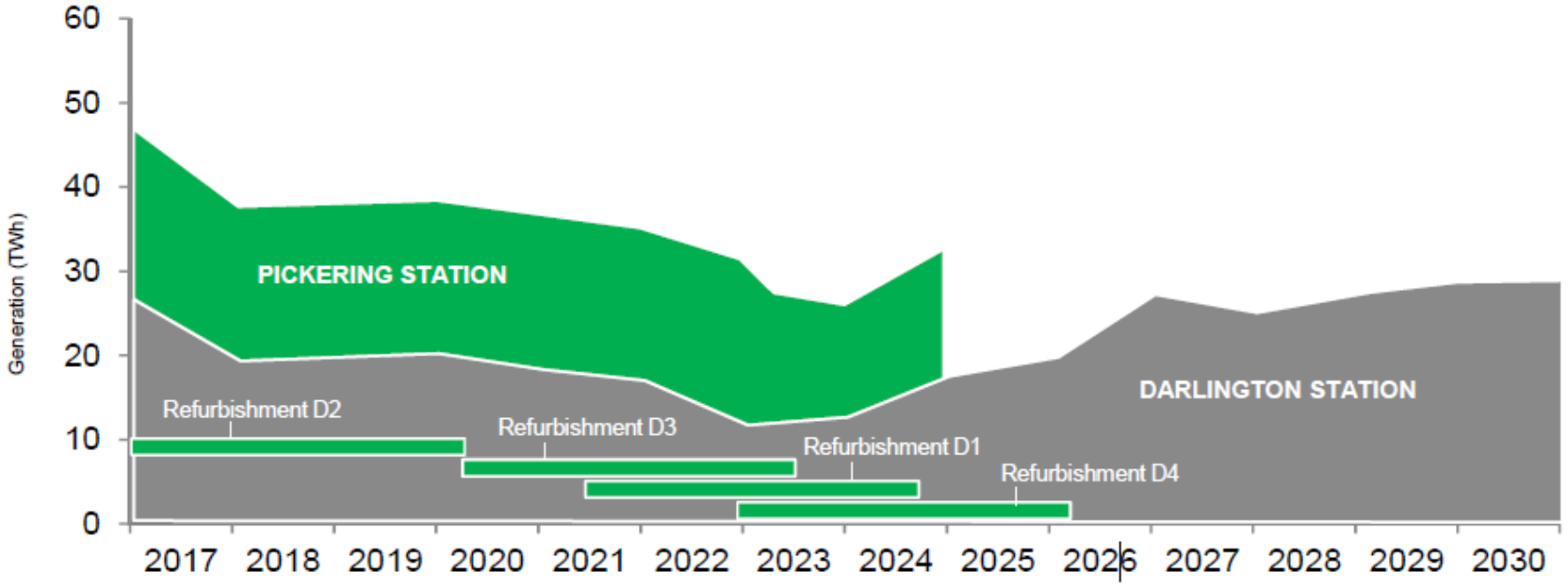
# Key Projects: Nuclear

### 1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

### 2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.




*Source: OPG Initial Public Debt Program, 2017*

# Key Projects: Renewables

## Biomass

**1. Atikokan**

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

**2. Thunder Bay**

Capacity: 153 MW

Converted from coal in 2014

## Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

## Hydroelectric

**1. Peter Sutherland Sr.**

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

**2. Lower Mattagami**

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

## Solar

**1. Nanticoke Solar**

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

# Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

# Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

| Director | Role | Appointed |
|---|---|---|
| 1. Bernard Lord | Chair | November 2013 |
| 2. Jeffrey Lyash | President and CEO of OPG | August 2015 |
| 3. William Coley | Director | January 2013 |
| 4. Elisabeth DeMarco | Director | April 2014 |
| 5. Jean Paul Gladu | Director | November 2015 |
| 6. John Herron | Director | November 2013 |
| 7. Ani Hotoyan-Joly | Director | March 2017 |
| 8. Wendy Kei | Director | March 2017 |
| 9. M. George Lewis | Director | February 2005 |
| 10. Margaret Mulligan | Director | December 2005 |
| 11. Yezdi Pavri | Director | September 2015 |
| 12. Gerry Phillips | Director | January 2013 |
| 13. Jim Reinsch | Director | August 2015 |
| 14. James Sheppard | Director | March 2017 |

# Compensation

## *2017 Statement of Executive Compensation*

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

| Category | **Performance Measure** | **Threshold Target** | **Business Plan Target** | **Stretch Target** | **2017 Results** | **Score (0 to 1.5)** |
|---|---|---|---|---|---|---|
| Social Licence | All Injury rate (AIR) | 0.49 | 0.37 | 0.31 | 0.48 | 0.54 |
| | Addressing Safety Focus Areas | CEO assessed target | | | 1.5 | 1.46 |
| | No significant impacts to OPG's reputation | | | | | |
| Financial Strength | Earnings Before Taxes, ($M) | 675 | 875 | 1075 | 1296 | 1.50 |
| | OM&A Expenses ($M) | 2675 | 2550 | 2425 | 2474 | 1.30 |
| Operational Excellence | Production (TWh) | 70.3 | 72.4 | 74.6 | 78.1 | 1.50 |
| Project Excellence | Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget | 100% | 97.50% | 95% | 120% | 0.00 |
| | Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone | 05-Aug-17 | 26-Jul-17 | 28-Jun-17 | 22-Jun-17 | 1.50 |
| | Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017 | All Bellows Severed | 50% End Fitting Removed | 400 Pressure Tubes Removed | 45% of End Fittings Removed | 0.95 |
| | Pump Generating Station: In service | 06-01-2017 | 04-01-2017 | 03-01-2017 | 02-04-2017 | 1.50 |
| | Peter Sutherland Generating Station: Both Units in service | 10-19-2017 | 06-30-2017 | 04-30-2017 | 03-31-2017 | 1.50 |
| | Total In-service Capital - | $578 (+/- 10% to +/- to 15%) | $578 (+/- 3% to +/- 10%) | $578 (to +/- 3%) | $625 (+8%) | 1.00 |
| | **Total Weighted Score[1]** | | | | | **1.19** |

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

Ontario

MINISTRY OF
ENERGY

# Ontario Power Generation 2018-2021 Business Plan

March 2018

# Ministry Request

- The Ministry of ENERGY is requesting that Treasury Board/Management Board of Cabinet (TB/MBC):

    1. NOTE the receipt of OPG's 2018-2021 Business Plan.

    2. NOTE that the Minister of Energy will provide concurrence with OPG's Business Plan.

# Purpose

- As required by the Memorandum of Agreement (MOA) between Ontario Power Generation and the Minister of Energy, OPG provided its Business Plan for 2018-2021 to the Ministry of Energy on February 12, 2018 for concurrence.
- The Minister's concurrence requires presentation of OPG's business plan before TB/MBC.
- Ministry of Energy staff have reviewed this plan in the context of key government priorities and recommend that TB provide approval.
- The Ministry of Energy review and analysis of OPG's business plan is supported by the Corporate and Electricity Finance Division of the Ontario Financing Authority (OFA).
- The following presentation identifies the key aspects of the business plan and how they interrelate.

# Overview

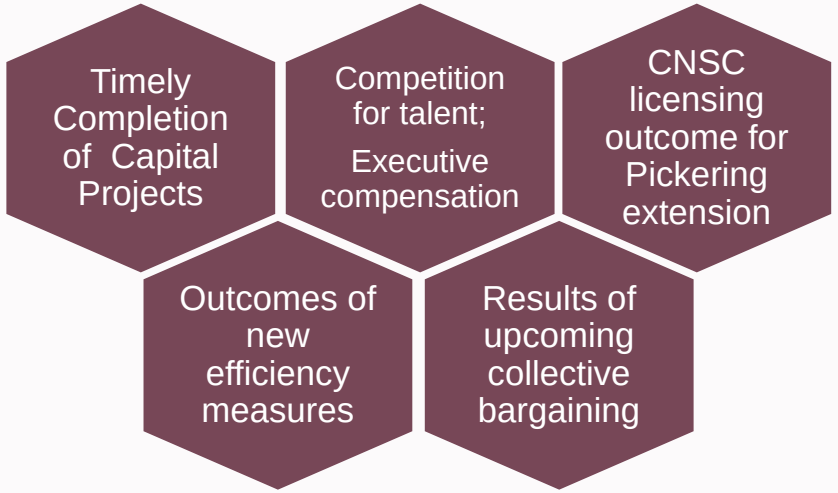
## Business Plan Elements

- The 2018-2021 Business Plan covers an important time for OPG for several reasons:




## Business Plan Risks

- Achieving financial performance targets is contingent on positive outcomes in a number of areas:




***OPG's ability to manage these elements & risks will determine if it is improves return to the Province and limits ratepayer costs.***

# Elements of Business Plan

1. **Electricity Production**
   - ❖ Higher than approved production improves financial performance through increased revenue.
   - ❖ Affected by capital projects (e.g., refurb) and Pickering Extension.

2. **Production Costs**
   - ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
   - ❖ Pickering's cost performance expected to improve relative to previous plan.

3. **Capital Projects**
   - ❖ Timely completion impacts production and project costs
   - ❖ Darlington Refurbishment on track- Unit 2 online in 2020.

4. **Operating Costs & Compensation**
   - ❖ Strategies to increase efficiencies and savings improve financial performance
   - ❖ Subject to collective bargaining that will take place in 2018.

5. **Fair Hydro Plan**
   - Adds ~$6 billion in debt by 2021; Provincial equity doubles by end of plan.
   - Generates net income for OPG ($465 million over 4 years)

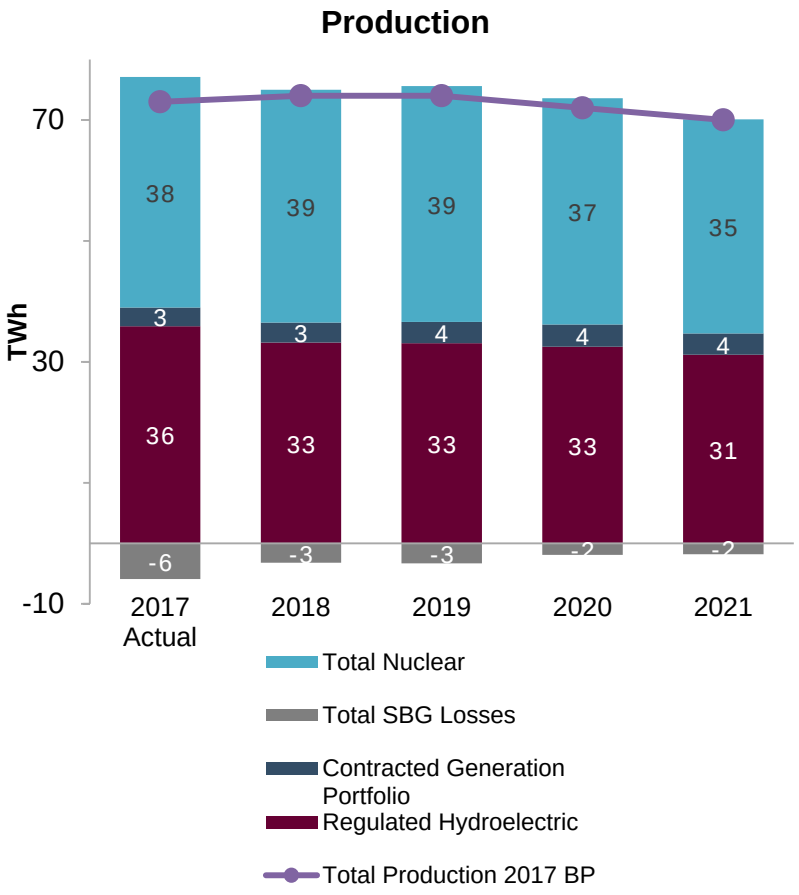
6. **Business Development**
   - Increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
   - Long-term need for new business lines outside of province

7. **Financial Performance**
   - ❖ Performance impacts Province's fiscal position Total Shareholder Return expected to improve over previous plans.

# Electricity Production

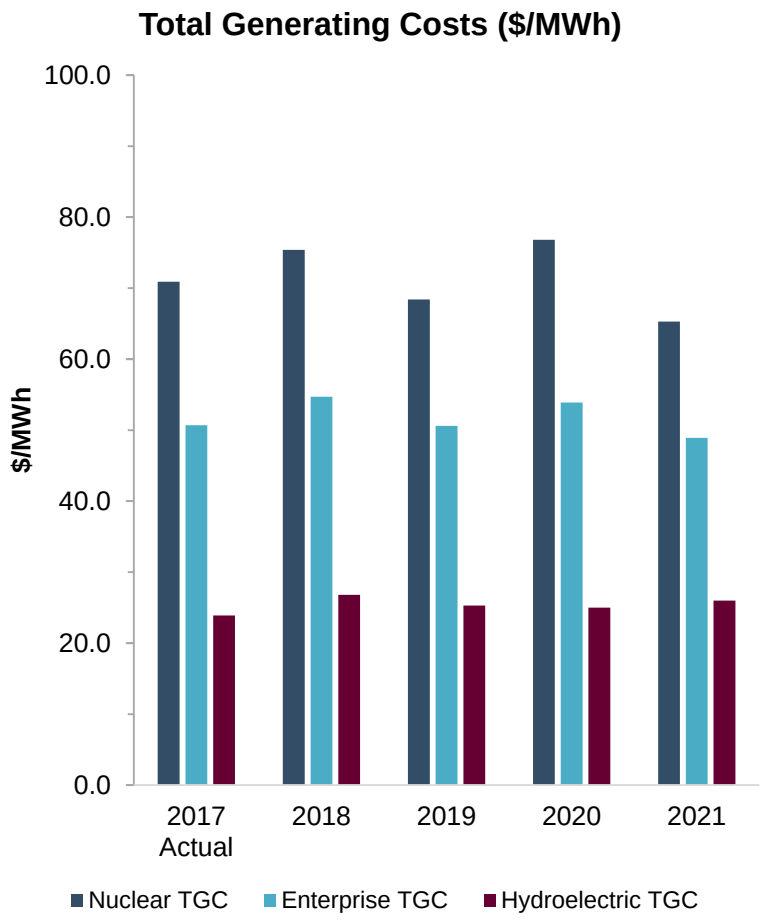
- ❖ Production increases improve financial performance through increased revenue.
- ❖ Forecasts affected by capital projects (e.g., Darlington Refurbishment); Pickering extension and efficiency strategies.

- The plan forecasts a total increase of 5.4 TWh compared to the last business plan.
- Increases are driven by higher production at Pickering Generating Station.
  - OPG will increase time between routine outages, allowing units to run longer.
  - Other reliability improvements reduce Pickering's 'forced loss rate'- (i.e., losses from unplanned shutdowns.)
- The forecasts assume CNSC will grant Pickering licence extension to 2024.
- Production decreases in 2020 when Darlington Unit 2 returns to service and Unit 3 is taken offline. There is also a lengthy planned outage at Pickering.
- The current Thunder Bay biomass energy supply agreement expires in January 2020. The station may participate in a future capacity auction.



# Cost of Production

- ❖ Cost targets fluctuate due to outages, water conditions and efficiency initiatives.
- ❖ Pickering's cost performance expected to improve relative to previous plan.



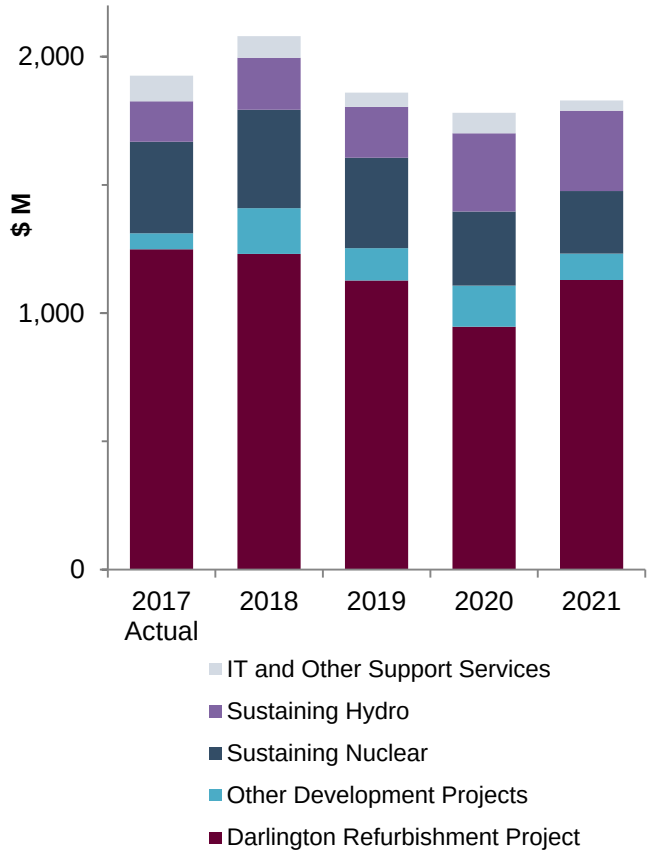

- Total Generating Cost (TGC) per MWh is OPG's measure of operational cost effectiveness.
  - TGC is a performance metric for executive compensation
  - Darlington Generating Station's TGC performance will be how OPG measures the long-term success of its OPG25 restructuring initiative.
- TGC targets fluctuate due to nuclear outages, efficiency initiatives and surplus-baseload generation adjustments due to high water levels.
- The production and cost forecasts are consistent with its OEB rate application. The set rates through 2021 provide planning stability.
  - If OPG exceeds production forecasts, it generates additional revenue. It must absorb costs if production is lower than forecast.

# Capital Projects

- ❖ Timely completion impacts production output and costs.
- ❖ Costs deemed imprudent for regulated projects negatively impact financial performance

- The plan includes $4.4 billion in capital expenditures for the Darlington Refurbishment project (DRP). Unit 2 is planned for return to service in early 2020.
- The plan includes $105 million in capital expenditures for the Heavy Water Storage(D2O) project, an enabling sub-project for the DRP that previously experienced delays and cost overruns (note: overall refurbishment has remained within budget and schedule).
- In its rate decision, OEB confirmed it will take a holistic view to assessing DRP costs, evaluating overall project performance against approved budget rather than an individual sub-project basis.
- Other capital expenditures include:
  - Ranney Falls re-development (2019 completion)
  - Nanticoke Solar (2019 completion)
  - Beck generating station upgrades (2022 completion)
  - Other sustaining capital (Hydro unit overhauls; equipment upgrades)
- The plan accelerates capital expenditures for OPG's digital transformation in support of improved efficiency.

**Total Capital Expenditures**



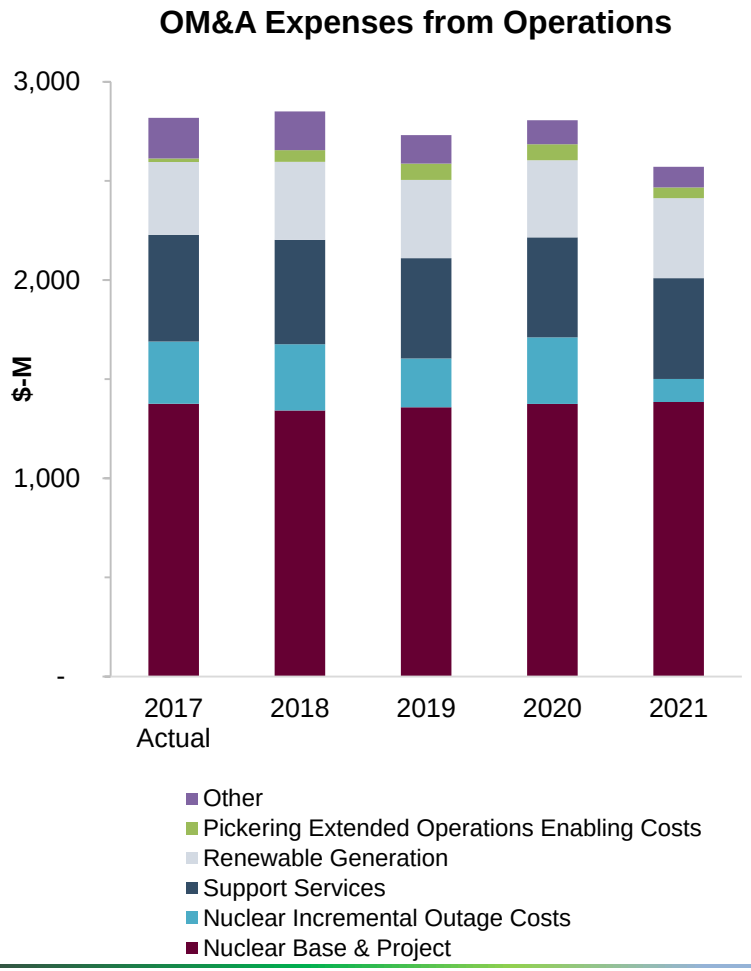
# Operating Costs (OM&A)

- ❖ Incremental efficiencies/savings improve financial performance
- ❖ OEB Decision reduces OM&A / compensation

- The plan targets a total decrease in OM&A expenditures of $600 million over four years. Annual spending decreases by $280 million in 2021 compared to 2018.
- The reductions will be achieved through new processes, technology upgrades and reducing nuclear plant outage frequencies.

**OPG25 Initiative**

- OPG25 is a plan to restructure OPG due to the closure of Pickering in 2024.
- The objective of OPG25 is to ensure operations remain cost-effective and that OPG is positioned for growth.
- The long-term target for the plan is having Darlington operate in the top-quartile for total generating costs.
- The initiative includes a staffing transition work stream, making interaction with unions critical.
- The 2018-21 business plan's cost reductions will help move OPG towards achieving the total target reductions post Pickering operations.

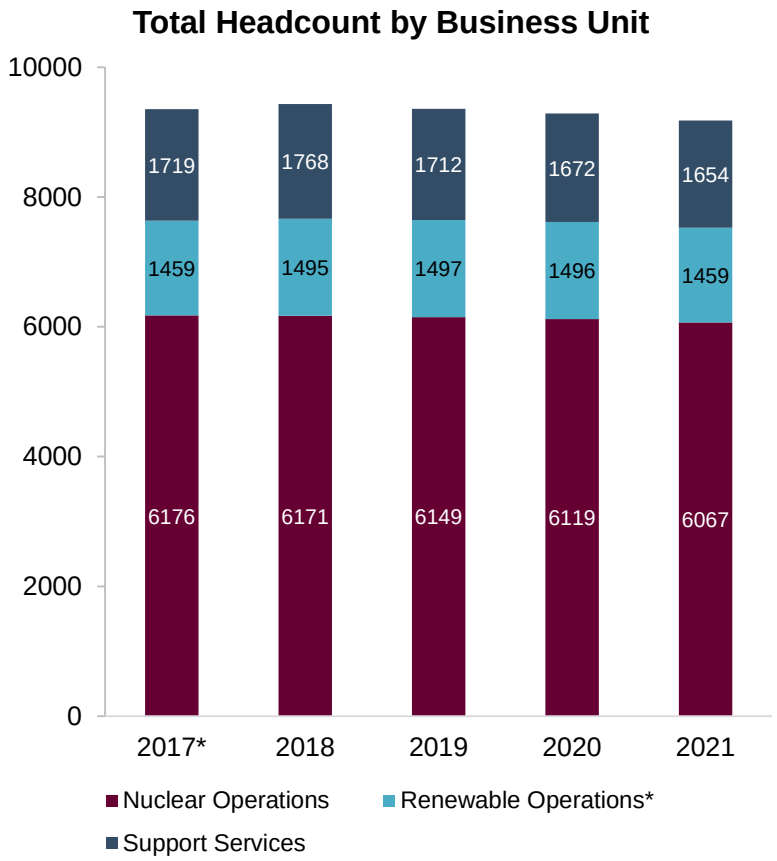


# Compensation

## *Collective Bargaining*

- ❖ Collective agreements expire in 2018.
- ❖ Results of collective bargaining will impact efficiency and cost-optimization initiatives.

- Collective bargaining impacts OPG's ability to reduce OM&A. Most employees belong to either the Power Workers Union (PWU) or Society of Energy Professionals (Society).
- Collective agreements with Society & PWU expire in 2018. Negotiated outcomes will impact OPG's ability to meet the plan's savings forecasts. Through collective bargaining, OPG hopes to:
  - Manage wage increases
  - Reduce future workforce costs including pension and benefits
  - Ensure future staff capability
  - Reduce downsizing costs resulting from Pickering closure*
- The plan identifies an accounting risk related to Pickering downsizing costs materializing prior to the next OEB rate application. This would affect net income in the year the costs were recognized.



# Compensation

## *Executive Compensation*

- ❖ Executive compensation program implemented in January 2017
- ❖ Compensation program benchmarks against comparator organizations

- OPG implemented an Executive Compensation Program in 2017 compliant with *O.Reg 304/16.*
- The program is designed to provide compensation that is at the 50th percentile of the market and focused on at-risk, performance based pay.
- In 2017, TB/MBC approved exemptions allowing OPG to compare against private sector and international companies.
- Overall compensation for all management group staff increases at 2% based on assumed inflation each year in the plan.
- Short-term incentives are based on individual performance and the corporate scorecard. Strong performance on the scorecard led to increases in executive incentives in 2017.
- Corporate scorecard measures for 2018 include:

**2016-2018 executive medium-term incentive performance metrics**
(on 3-year cycle ending 2018)

- **Return on Equity**
- **Total Generating Cost**
- **Darlington Refurbishment Major Milestones**

**Social Licence**: Total Recordable Injury Frequency; no significant events impacting OPG's reputation

**Financial Strength**: Earnings Before Tax (excluding the Nuclear Waste Management segment), Plan Operating OM&A Expenses.

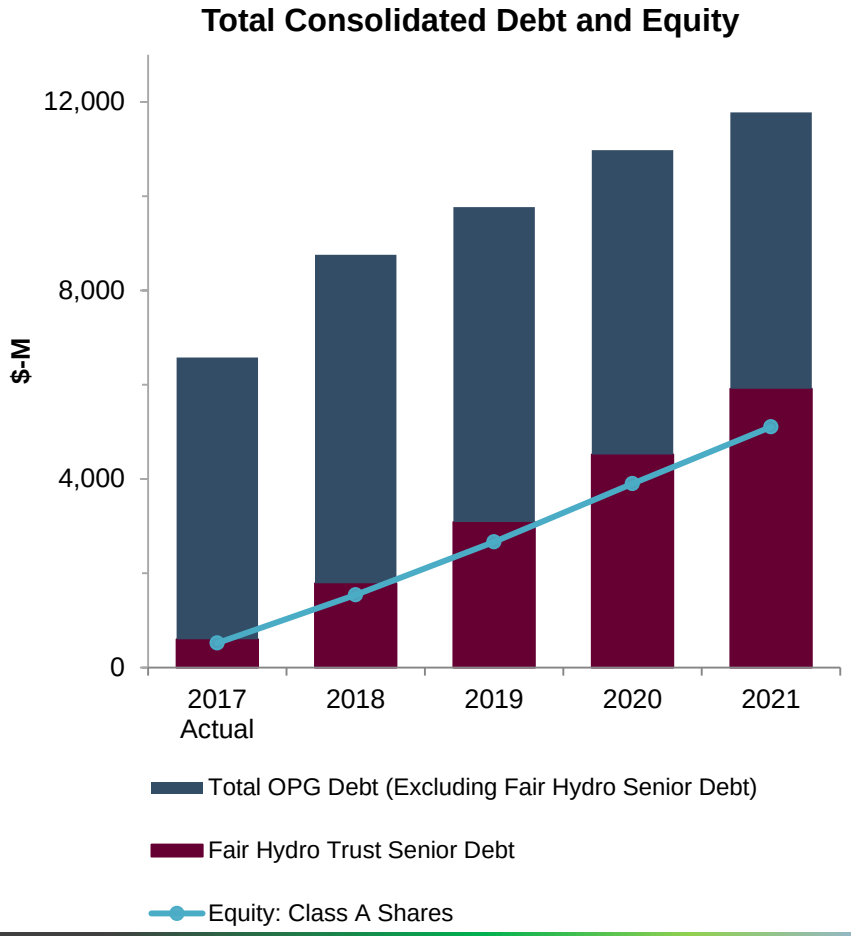
**Operational Excellence**: Total OPG production adjusted for Surplus Baseload Generation

**Project Excellence**: DRP costs and schedule; Peter Sutherlands Sr. Generating Station, and total in-service capital

# Fair Hydro Plan

- ❖ FHP is managing the deferral of a portion of Global Adjustment (GA) costs.
- ❖ OPG earns revenue and incurs debt; Provincial equity in OPG doubles by 2021.
- ❖ While a new source of revenue for OPG, revenue is paid by Ontario ratepayers.

- In 2017, OPG began its role as OFHP Financial Services Manager (FSM).
- The Fair Hydro Trust contributes to increasing amounts of net income, growing from $10 million in 2018 to $225 million in 2021.
  - This reflects the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust.
- As the Province provides more funding to facilitate asset purchases in exchange for shares in the company, the government's equity increases, lowering ROE.
- The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.



# Business Development

- ❖ OPG hopes to grow its business and increase revenue through modest hydro expansion, solar, nuclear services & low-carbon technology.
- ❖ Long-term need for new business lines outside of province.

- OPG hopes to grow its business by investing in commercial innovation, project development and asset acquisition.
- The business plan references organic and non-organic investments:
  - Organic investments are in-house project development of generation and energy products in Ontario. The plan allocates incremental capital funding of ~$200 million for organic investments.
  - Non-organic investments are new opportunities in Ontario. These investments are not included in the plan, however, OPG forecasts up to $3 billion would be available for such investments.

**Business Development investment categories:**

**Innovation & Services**
*OPG will consider investing in near commercial emerging technologies*

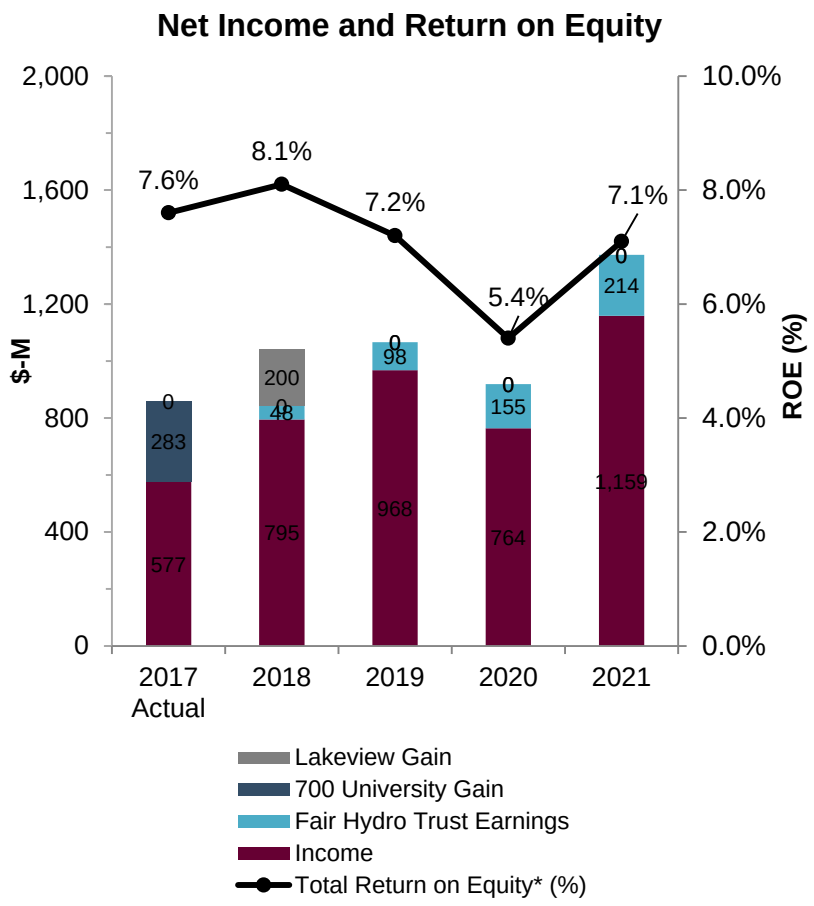
**Acquisition and Development**
*OPG will develop assets and consider acquisitions in Ontario and other North American markets*

- As the Shareholder, the Province may need to provide approvals for certain investments (e.g., development and acquisitions).
  - The Ministry of Energy plans to develop a policy framework to guide these approvals.

# Financial Performance

*Business Plan Results as presented by OPG*

- ❖ Plan forecasts total net income to reach $1.37 billion in 2021, from $860 million in 2017
- ❖ OEB Decision provides rate stability over the planning period.




- OPG shareholder return (Net income + PILS) are consolidated to the Province.
- The plan reflects the Ontario Energy Board's (OEB) December 2017 Decision on OPG's regulated rates through 2021, providing stability in the planning period.
- Return on Equity (excluding impact of Fair Hydro Trust) increases from 5.3% in 2017 to 8.1% in 2021. ROE is a performance metric for executive compensation.
- Should OPG fail to meet targets for production, operating cost reductions or capital expenditures, net income improvements may not materialize.
- Net income in 2017/18 is impacted by one-time asset sales (Head Office and Lakeview), ~~which~~ with net proceeds ~~will be~~ credited to the Trillium Trust.

# Financial Performance

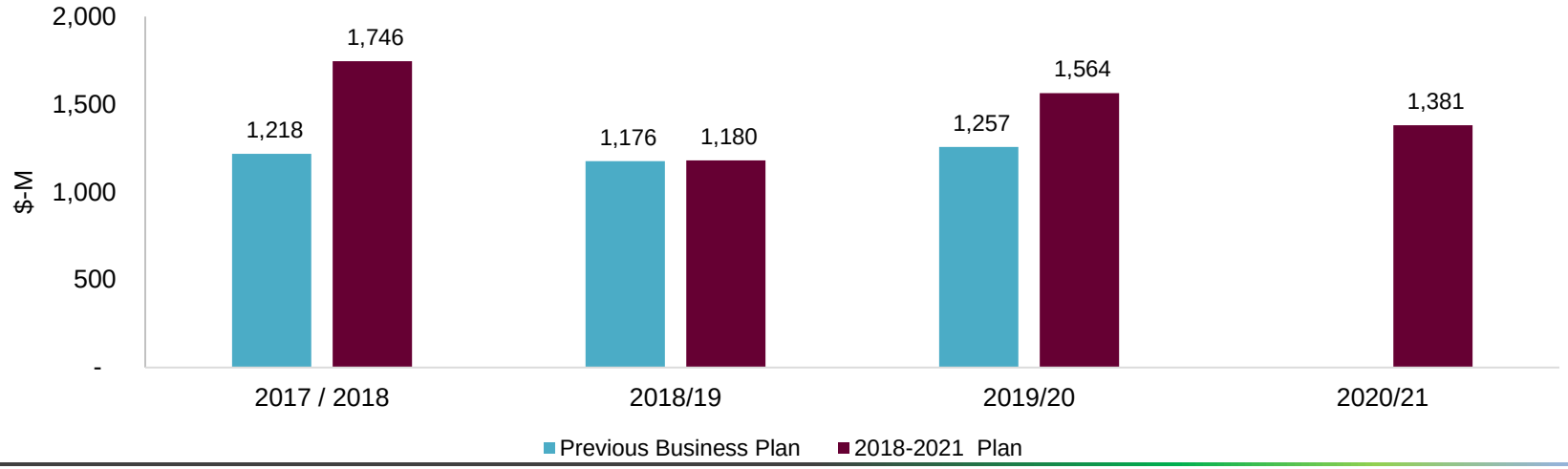
*2018-21 Business Plan compared to previous plan*

- ❖ Improved net income and shareholder return over previous plans.
- ❖ Projections impacted by efficiency measures and one-time real estate gains.

- The plan's total shareholder return is higher than last year's 2017-19 business plan.
- The financial performance reflects increased efficiency leading to revenue increases from higher production and lower operating costs
- The plan assumes the sale of Lakeview will be complete in 2017/18, resulting in $200M in net income and $70 million in PILS. The sale was not included in last year's plan.
  - OPG closed the sale of the ~~has a purchase agreement for~~ Lakeview site~~, anticipated to close~~ in March, 2018.

**Total Shareholder Return**

*2018-21 BP vs. Previous Business Plan*



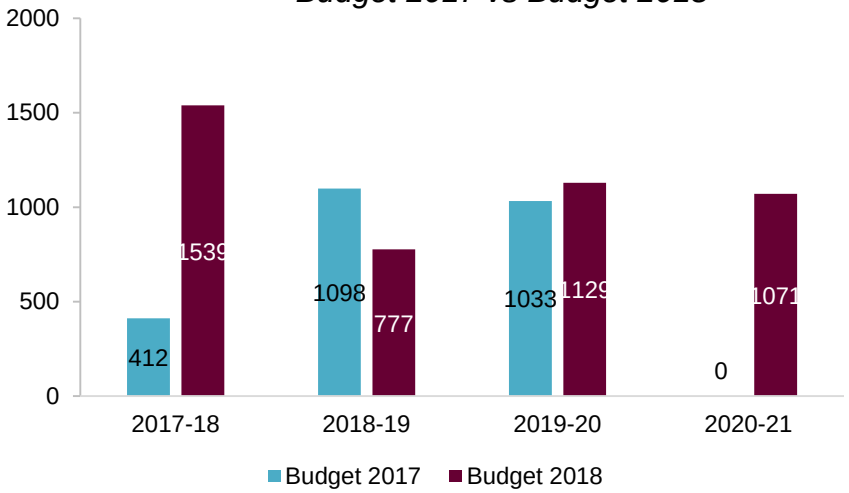
# Financial Performance:[OFA to review]

*Impacts to Province*

- The Ministry of Finance is responsible for incorporating OPG's financial projections into the Province's Fiscal Plan and fiscal plan updates, and Treasury Board Secretariat is responsible for the fiscal consolidation of OPG's financials on the Province's financial statements, which may include accounting adjustments.
- Budget 2018 reflects the impacts of OPG's 2018-2021 Business Plan

- When OPG's planning projections and financial results are consolidated into the Province's Budget and Public Accounts ~~financials~~, some adjustments are required
  - **IFRS:** OPG uses US GAAP accounting standards for financial reporting. The Province consolidates OPG's results adjusted to an International Financial Reporting Standards (IFRS) basis.
  - **Nuclear Funds:** For the operating statement for Public Accounts, an adjustment is made to a realised gains basis, vs a fair value basis on OPG's statements.
  - **Fair Hydro Income:** While OPG separates out this income in its Business Plan, OPG's Financial Services Manger revenue is added to OPG net income when consolidated.

***Total OPG Revenues to the Province***
*Budget 2017 vs Budget 2018*




2017/18 positive variance due to:
- $646M for real estate sales included as OPG revenue in Budget 2018. In Budget 2017, ~~not in Budget 2017 as~~ projected OPG real estate revenues ~~those revenues~~ were included in the Sales and Rentals line.
- Positive ONFA Adjustments included in Budget 2018 not in Budget 2017
- Lower IFRS adjustment in Budget 2018 than Budget 2017

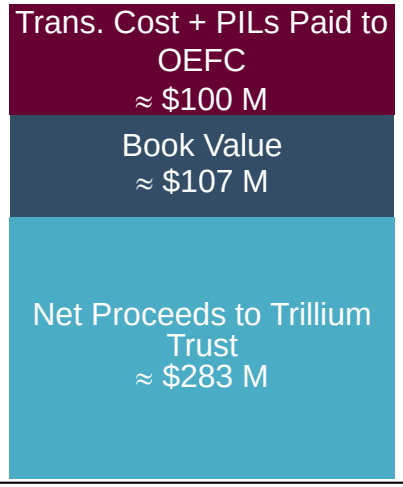
2018/19 negative variance due to:
- Negative IFRS adjustment included in Budget 2018

# Financial Performance

*Contribution to the Trillium Trust*

- Net proceeds from the sale of OPG's ~~its~~ Head Office (700 University) and Lakeview site are paid by OPG to the CRF and credited to the Trillium Trust.
- The Province ~~will~~ has received a dividend payment from OPG for the OPG Head Office Sale. OPG will be required to pay the net proceeds from the Lakeview sale once a Trillium Trust regulation is filed.~~gains on these sales.~~
- The Head Office sale closed in April 2017. Lakeview ~~expected to~~ closed in March, 2018.

**Head Office: ~~Designated~~ Net Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: December 2015
- Sale closed: April 2017
- Amount credited to Trillium Trust: Mar 2018

**Lakeview: Estimated Net Proceeds to Trillium Trust from OPG**




- Shareholder Declaration & Resolution received: June 2016
- ~~Expected~~ Sale closed: March 2018
- Regulation required to prescribe amounts to Trillium trust

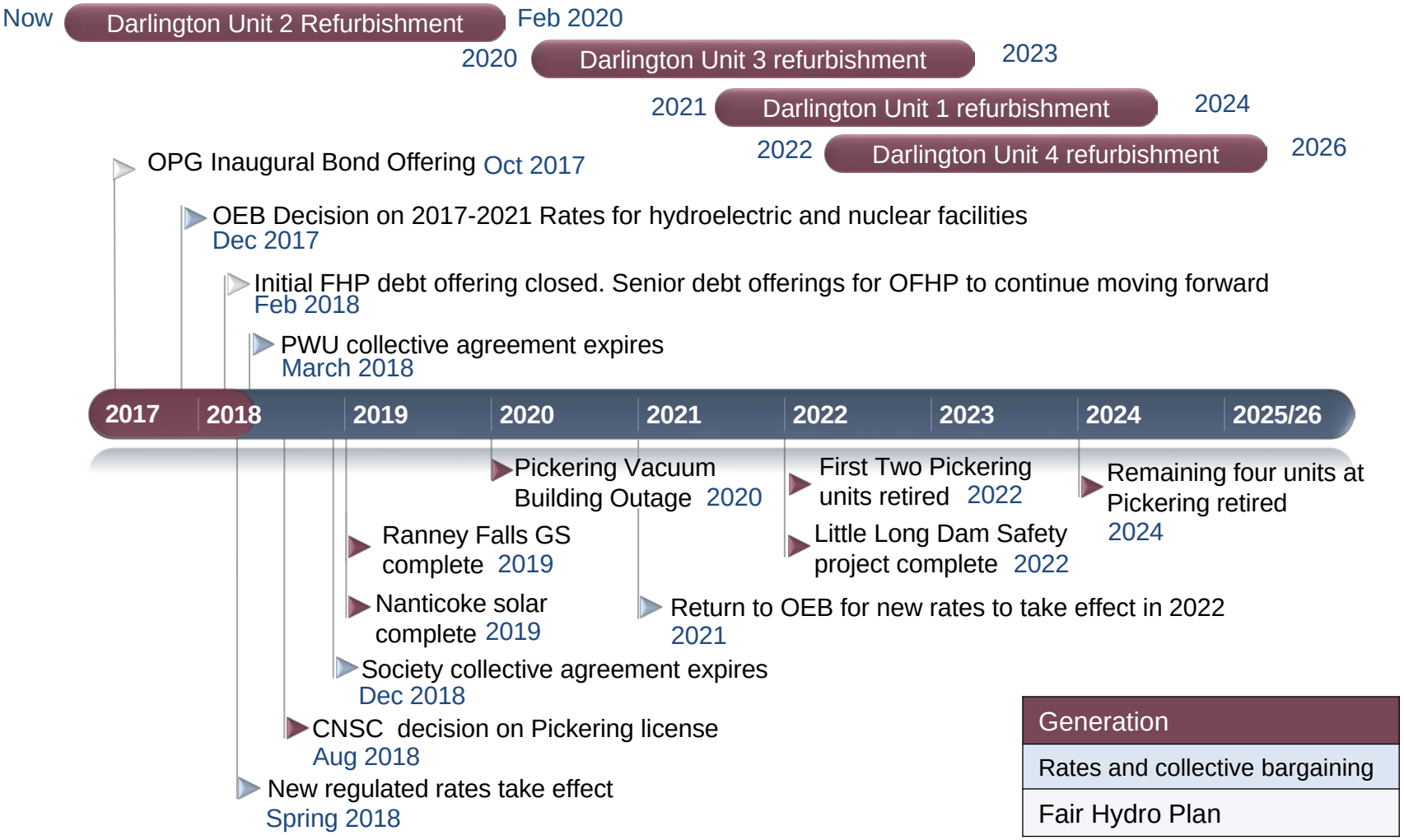
# Considerations

- Based on these materials, ENERGY is seeking approval to provide OPG with business plan concurrence.
- At this point OPG has rate stability through the planning period and has demonstrated success in key projects including Darlington refurbishment. The plan is in line with government expectations on reducing costs in order to drive value for Ontario ratepayers and the Province, as Shareholder.
- OPG identified risks that the Ministry will continue to monitor. These include
  - Meeting efficiency targets for cost-savings and production.
  - Successful collective bargaining negotiations with PWU and Society; and
  - Completion of capital projects on budget and schedule
- OPG will continue to seek new business opportunities within Ontario and other jurisdictions. OPG will seek comfort from the Province for any new acquisitions.
- OPG will consider investing in near-commercial emerging technologies, acquisitions and development.

# Appendix

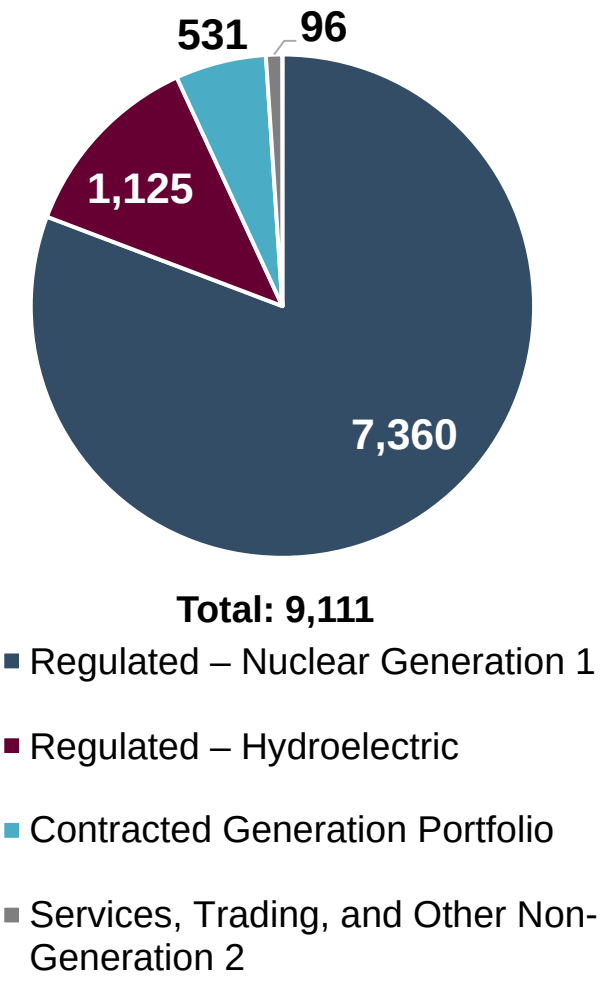
# Timeline

- Outcomes from the Business Plan are impacted by the following events:



# Company Profile

## 2017 Average Full-Time Employees

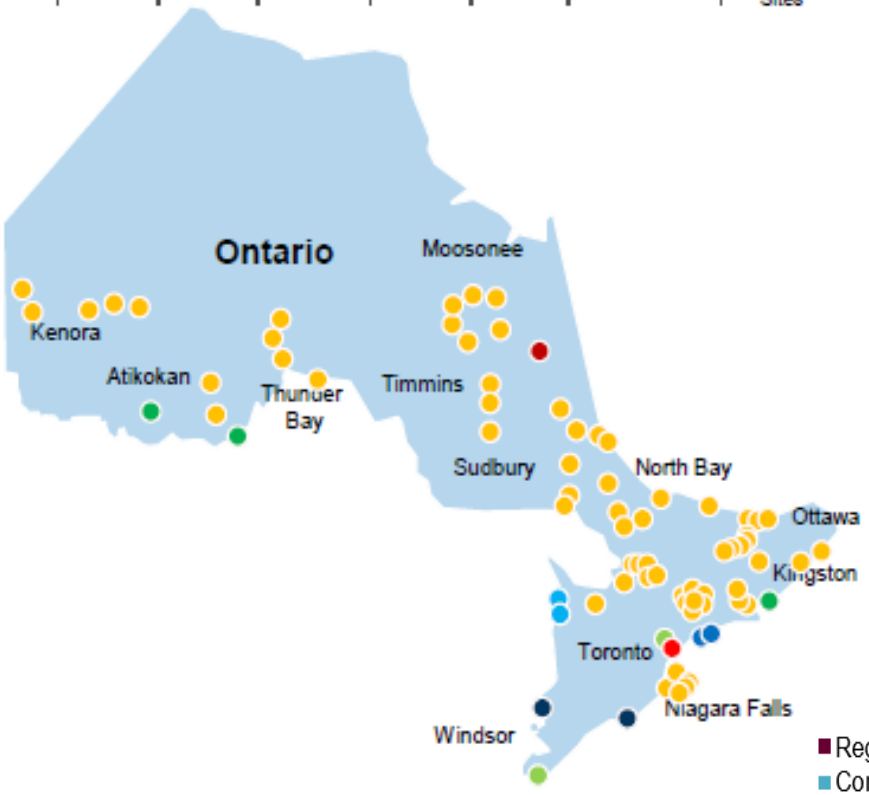


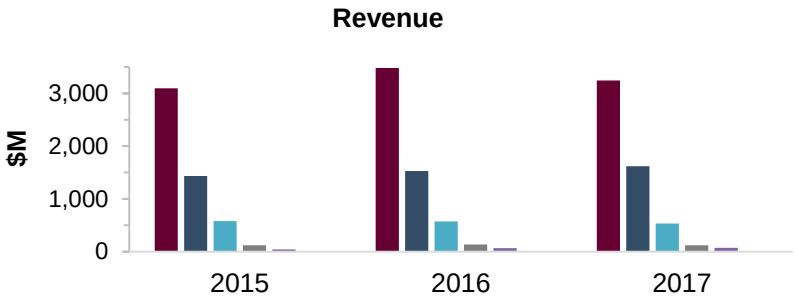

- Majority of OPG's employees are represented by one of two unions:
  1. The Power Workers' Union (PWU); and
  2. The Society.
- The PWU includes most workers below the level of first line manager
- The Society includes supervisors, professional engineers, scientists and other professionals.
- Construction work is performed through 19 craft unions.

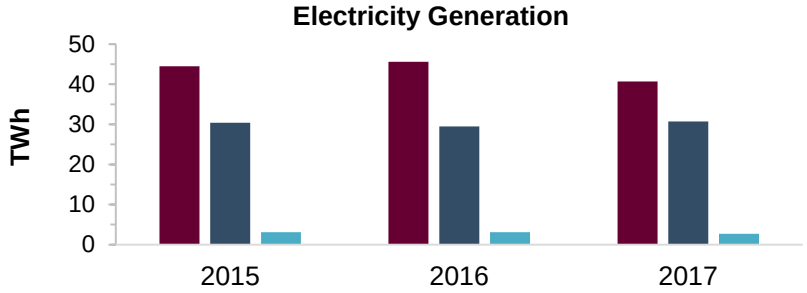
# Company Profile

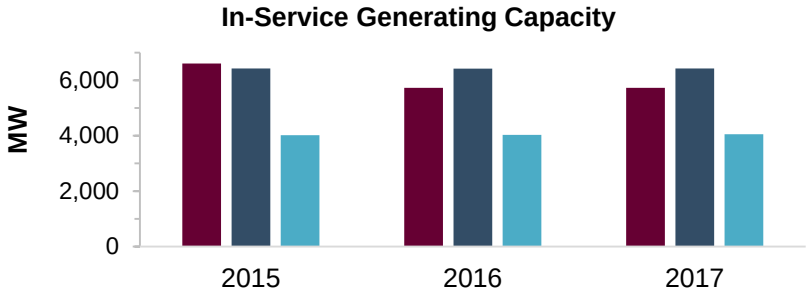
## Map of OPG Generating Stations:

| 2 | 2 | 3 | 2 | 65 | 1 | 1 | 2 |
|---|---|---|---|---|---|---|---|
| Nuclear Stations | Leased Nuclear Stations | Thermal Stations | Co-Owned Gas-Fired Stations | Hydro-electric Stations | Wind Power Turbine | Hydroelectric Project Under Construction [1] | Brownfield Coal Generation Sites |




- Regulated – Nuclear Generation
- Regulated – Hydroelectric
- Contracted Generation Portfolio 1
- Regulated – Nuclear Waste Management
- Services, Trading, and Other Non-Generation

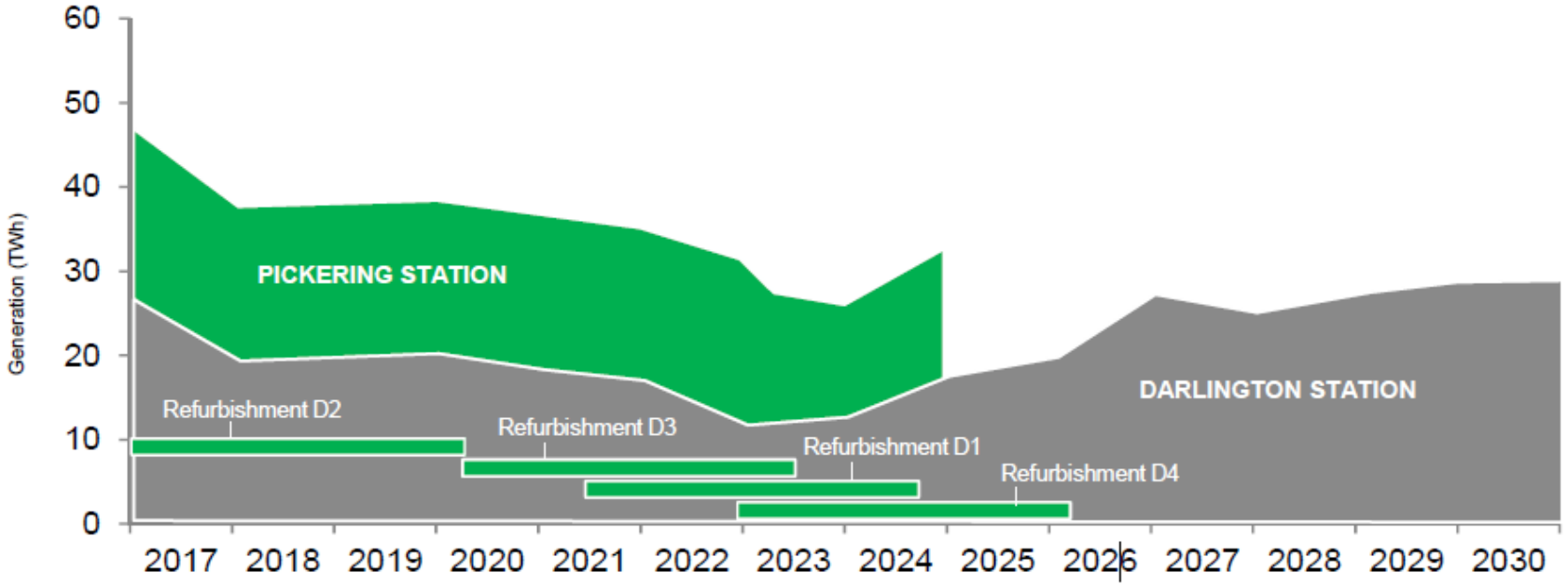
# Key Projects: Nuclear

### 1. Pickering Extension

- OPG is continuing work to extend operations of the Pickering GS to 2024. It is currently licensed to operate to 2020.
- OPG has applied for a license renewal from the CNSC. The ruling is expected in August 2018.

### 2. Darlington Refurbishment

- OPG is refurbishing the Darlington Nuclear station to extend the operating life of the station by 30 years.
- Status: tracking on schedule and budget.
- Total Budget: $12.8 billion.




*Source: OPG Initial Public Debt Program, 2017*

# Key Projects: Renewables

## Biomass

**1. Atikokan**

Capacity: 205 MW

Converted from coal in 2014

Capex: ~$170M

**2. Thunder Bay**

Capacity: 153 MW

Converted from coal in 2014

## Indigenous Relations

OPG's corporate governance includes an Indigenous Relations policy to help build and develop mutually beneficial working relationships with Indigenous communities proximate to the Company's present and future operations.

Renewables

## Hydroelectric

**1. Peter Sutherland Sr.**

Capacity: 28 MW

Completed: March 2017

Capex: <$300M

**2. Lower Mattagami**

Capacity: 438 MW

Completed: 2014

Capex: $2.5BN

## Solar

**1. Nanticoke Solar**

Project partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation to build the new facility.

Capacity: 44 MW

Commenced: Q4 2017

Expected completion: 2019

# Role of OFHP Financial Services Manager

- In June 2017, the Province enacted the *Ontario Fair Hydro Plan Act, 2017* in order to ensure the costs and benefits associated with the Province's clean energy initiatives are allocated fairly between present and future electricity consumers.
    - The policy goals of the Act are being achieved through the refinancing of a portion of the Global Adjustment (GA).
    - OPG was appointed Financial Services Manager (FSM) under the Act.

- OPG's duties as FSM include:
    - Establishing one or more financing entities to incur funding obligations. OPG established the Fair Hydro Trust in 2017.
    - Preparing a financing plan to evaluate how and when funding obligations should be incurred.
    - Administering investment assets purchased from IESO
    - Determining the monthly clean energy adjustment for each reference period
    - Establishing and charging fees to recover costs, expenditures and earn a return
    - Seeking best available terms for incurrence of a funding obligation
    - Fulfilling various reporting requirements

# Board of directors

- OPG's Board of Directors is made up of 14 individuals. Each Director holds office until he or she resigns or a successor is elected or appointed:

| Director | Role | Appointed |
|---|---|---|
| 1. Bernard Lord | Chair | November 2013 |
| 2. Jeffrey Lyash | President and CEO of OPG | August 2015 |
| 3. William Coley | Director | January 2013 |
| 4. Elisabeth DeMarco | Director | April 2014 |
| 5. Jean Paul Gladu | Director | November 2015 |
| 6. John Herron | Director | November 2013 |
| 7. Ani Hotoyan-Joly | Director | March 2017 |
| 8. Wendy Kei | Director | March 2017 |
| 9. M. George Lewis | Director | February 2005 |
| 10. Margaret Mulligan | Director | December 2005 |
| 11. Yezdi Pavri | Director | September 2015 |
| 12. Gerry Phillips | Director | January 2013 |
| 13. Jim Reinsch | Director | August 2015 |
| 14. James Sheppard | Director | March 2017 |

# Compensation

## *2017 Statement of Executive Compensation*

- OPG exceeded many of the measures in its Corporate Scorecard, impacting incentive payments.
- Scorecard is based on a predetermined scale of Threshold/Business Plan/Stretch targets (i.e., low/medium/high) and given a weighting. The scorecard is summarized below.

| Category | **Performance Measure** | **Threshold Target** | **Business Plan Target** | **Stretch Target** | **2017 Results** | **Score (0 to 1.5)** |
|---|---|---|---|---|---|---|
| Social Licence | All Injury rate (AIR) | 0.49 | 0.37 | 0.31 | 0.48 | 0.54 |
| | Addressing Safety Focus Areas | CEO assessed target | | | 1.5 | 1.46 |
| | No significant impacts to OPG's reputation | | | | | |
| Financial Strength | Earnings Before Taxes, ($M) | 675 | 875 | 1075 | 1296 | 1.50 |
| | OM&A Expenses ($M) | 2675 | 2550 | 2425 | 2474 | 1.30 |
| Operational Excellence | Production (TWh) | 70.3 | 72.4 | 74.6 | 78.1 | 1.50 |
| Project Excellence | Refurbishment Project Cost – 2017 actual expenditures ($M) as a percentage of approved 2017 budget | 100% | 97.50% | 95% | 120% | 0.00 |
| | Refurbishment Unit 2 Critical Path Execution – Commencement of Feeder cabinet removal (Milestone | 05-Aug-17 | 26-Jul-17 | 28-Jun-17 | 22-Jun-17 | 1.50 |
| | Refurbishment Unit 2 Critical Path Execution: Progress of Critical path on Dec 31, 2017 | All Bellows Severed | 50% End Fitting Removed | 400 Pressure Tubes Removed | 45% of End Fittings Removed | 0.95 |
| | Pump Generating Station: In service | 06-01-2017 | 04-01-2017 | 03-01-2017 | 02-04-2017 | 1.50 |
| | Peter Sutherland Generating Station: Both Units in service | 10-19-2017 | 06-30-2017 | 04-30-2017 | 03-31-2017 | 1.50 |
| | Total In-service Capital - | $578 (+/- 10% to +/- to 15%) | $578 (+/- 3% to +/- 10%) | $578 (to +/- 3%) | $625 (+8%) | 1.00 |
| | **Total Weighted Score[1]** | | | | | **1.19** |

Exceeded Stretch Target
Exceeded BP Target
Below BP Target
Below Threshold

ONTARIO POWER GENERATION

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from Ontario Power Generation

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www.opg.com

May 15, 2018

# OPG REPORTS 2018 FIRST QUARTER FINANCIAL RESULTS

## *Strong results attributable to former Lakeview generating station land sale and continued strong nuclear generation performance*

**[Toronto]:** – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $535 million for the first quarter of 2018, inclusive of a one-time after-tax gain of $205 million related to the sale of the former Lakeview generating station (GS) property, compared to $64 million for the same period in 2017.

"As Ontario's publicly-owned electricity generator, we are pleased to report our strong first quarter results that have resulted in significant net income to our shareholder, the Province of Ontario. We remain focused on continuing to supply Ontario with safe, reliable, and low-cost power that is more than 99 per cent free of greenhouse gas emissions to help moderate customer's electricity bills, and are investing in our assets for the benefit of Ontarians for years to come," said Jeff Lyash, OPG President and CEO. "Canada's single largest investment in low-cost, clean energy, the refurbishment of the Darlington Nuclear Station, remains on time and on budget due to the hard work and dedication of our employees and partners. Refurbishing this public asset will ensure OPG remains Ontario's largest provider of low-cost electricity for another 30 years, generating clean power that is virtually free of carbon emissions."

Lyash continued, "In addition to investing in the Darlington Nuclear Station, OPG has begun the relicensing process to keep the Pickering Nuclear Station operating until 2024. Running Pickering until 2024 will save electricity customers up to $600 million and benefit Ontario by contributing over $12 billion to the economy. Pickering remains a safe, efficient and reliable public asset that can continue to supply low-cost electricity for up to 1.5 million homes each day, with almost no carbon emissions."

"Major contributors to the strong financial results for the quarter include the one-time gain on the sale of OPG's former Lakeview generating station lands in Mississauga, Ontario in March, the net proceeds of which will be transferred to our shareholder, and the continued strong nuclear generation performance," added Lyash. "In the same month as the Lakeview sale, a special dividend of $283 million from last year's sale of our head office premises was transferred to the Province."

The increase in net income in the first quarter of 2018 is also attributable to the impact of the new regulated prices for OPG's nuclear and most of its hydroelectric generation,

resulting from the Ontario Energy Board's (OEB) decision on OPG's application for new regulated prices for the 2017-2021 period issued in December 2017.

The OEB issued the final payment amounts order on the application in March 2018, allowing OPG to begin collecting revenues based on the new regulated prices. Taking into account the impact of the OEB's decision, OPG continues to provide electricity at a price that is approximately 40 per cent less than the average of other generators. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

**Generating and Operating Performance**

Electricity generated during the three months ended March 31, 2018 increased to 18.8 terawatt hours (TWh) from 18.6 TWh for the same quarter in 2017.

*Regulated – Nuclear Generation Segment*

Higher nuclear generation of 0.4 TWh during the three months ended March 31, 2018 was primarily due to fewer planned outage days at the Darlington GS.

For the three months ended March 31, 2018, the unit capability factor for the operating units at the Darlington GS was 96.5 per cent, compared to 85.3 per cent for the same quarter in 2017. The increase was primarily due to a lower number of planned outage days at the station.

At the Pickering GS, the unit capability factor decreased to 74.5 per cent for 2018, compared to 78.5 per cent for the same quarter in 2017, primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

*Regulated – Hydroelectric Segment*

Lower generation from the regulated hydroelectric stations of 0.3 TWh during the three months ended March 31, 2018, compared to the same quarter in 2017, was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

The availability of 87.3 per cent at these stations in 2018 was lower than 89.5 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

*Contracted Generation Portfolio Segment*

Generation from the Contracted Generation Portfolio during the three months ended March 31, 2018 increased by 0.1 TWh compared to the same quarter in 2017.

The availability of these hydroelectric stations for the three months ended March 31, 2018 was 80.1 per cent, compared to 83.6 per cent for the same quarter in 2017. The decrease in the availability was primarily due to a higher number of planned outage days at the Little Long GS on the Lower Mattagami River.

*Total Generating Cost*

The Enterprise Total Generating Cost per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same quarter in 2017. The increase was mainly a result of higher operations, maintenance and administration expenses and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

**Generation Development**

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the first quarter of 2018 were as follows:

*Darlington Refurbishment*

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In early May 2018, OPG completed the removal of the existing reactor components, signifying the completion of the second major segment of the Unit 2 refurbishment. The refurbishment of Unit 2 has now transitioned into the third major segment, the installation and reassembly of reactor components. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is progressing with planning activities on the refurbishment of Unit 3 and ensuring that lessons learned from the Unit 2 refurbishment are being incorporated. OPG is also entering into commitments to procure major components that require long lead times. Execution of the prerequisite activities for the Unit 3 refurbishment have commenced. The Unit 3 refurbishment is expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the refurbishment of Unit 3. In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $4.7 billion as at March 31, 2018.

*Ranney Falls Hydroelectric GS*

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

*Nanticoke Solar Facility*

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the Independent Electricity

System Operator, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars – except where noted)* | **2018** | **2017** |
| Revenue | **1,407** | 1,176 |
| Fuel expense | **155** | 155 |
| Operations, maintenance and administration | **722** | 708 |
| Depreciation and amortization | **186** | 167 |
| Other (gains) expenses, net [1] | **(227)** | 47 |
| Income before interest and income taxes | **571** | 99 |
| Net interest expense | **19** | 19 |
| Income tax expense | **13** | 12 |
| Net income | **539** | 68 |
| **Net income attributable to the Shareholder** | **535** | 64 |
| **Net income attributable to non-controlling interest** [2] | **4** | 4 |
| ***Income before interest and income taxes*** | | |
| Electricity generation business segments | **324** | 139 |
| Regulated – Nuclear Waste Management | **(33)** | (47) |
| Fair Hydro Trust | **4** | - |
| Other [1] | **276** | 7 |
| Total income before interest and income taxes | **571** | 99 |
| ***Cash flow*** | | |
| Cash flow provided by operating activities | **226** | 168 |
| ***Electricity generation (TWh)*** | | |
| Regulated – Nuclear Generation | **10.4** | 10.0 |
| Regulated – Hydroelectric | **7.7** | 8.0 |
| Contracted Generation Portfolio [3] | **0.7** | 0.6 |
| Total electricity generation | **18.8** | 18.6 |
| ***Nuclear unit capability factor (per cent)*** [4] | | |
| Darlington Nuclear GS | **96.5** | 85.3 |
| Pickering Nuclear GS | **74.5** | 78.5 |
| ***Availability (per cent)*** | | |
| Regulated – Hydroelectric | **87.3** | 89.5 |
| Contracted Generation Portfolio – hydroelectric stations | **80.1** | 83.6 |
| ***Equivalent forced outage rate*** | | |
| Contracted Generation Portfolio – thermal stations | **0.3** | 1.6 |
| *Enterprise Total Generating Cost (TGC) per MWh for the three months ended March 31, 2018 and March 31, 2017 ($/MWh)* [5] | **49.84** | 47.86 |
| *Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended March 31, 2018 and December 31, 2017 (%)* [5] | **11.5** | 7.6 |

[1] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

[2] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 per cent in April 2017.

[3] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[4] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[5] Enterprise TGC per MWh and ROE Excluding AOCI are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three months ended March 31, 2018, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim financial statements and Management's Discussion and Analysis as at and for the three months ended March 31, 2018 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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# ONTARIO POWER GENERATION INC.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## 2018 FIRST QUARTER REPORT

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ONTARIO POWER GENERATION

# ONTARIO POWER GENERATION INC.
## MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three months ended March 31, 2018. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Annual Information Form, and MD&A as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Changes in Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP.* This MD&A is dated May 15, 2018.

### FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan and forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this

MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

## THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at March 31, 2018, OPG's electricity generation portfolio had an in-service capacity of 16,218 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS), and OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP. Income from these leased stations is included as leasing revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2017 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

### In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of March 31, 2018 and December 31, 2017 was as follows:

| | As at | |
|---|---|---|
| *(MW)* | **March 31 2018** | **December 31 2017** |
| Regulated – Nuclear Generation [1] | **5,728** | 5,728 |
| Regulated – Hydroelectric | **6,426** | 6,426 |
| Contracted Generation Portfolio [2] | **4,064** | 4,056 |
| Total | **16,218** | 16,210 |

[1] The in-service generating capacity as of March 31, 2018 and December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS (Darlington GS). The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the three months ended March 31, 2018, total in-service capacity increased by 8 MW. The increase was due to the completion of the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which was returned to service in February 2018 as part of the Contracted Generation Portfolio segment.

## HIGHLIGHTS

### Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three months ended March 31, 2018, compared to the same period in 2017, are discussed below. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Revenue | **1,407** | 1,176 |
| Fuel expense | **155** | 155 |
| Operations, maintenance and administration | **722** | 708 |
| Depreciation and amortization | **186** | 167 |
| Other (gains) expenses, net [1] | **(227)** | 47 |
| Income before interest and income taxes | **571** | 99 |
| Net interest expense | **19** | 19 |
| Income tax expense | **13** | 12 |
| Net income | **539** | 68 |
| Net income attributable to the Shareholder | **535** | 64 |
| Net income attributable to non-controlling interest [2] | **4** | 4 |
| *Electricity production (TWh)* [3] | **18.8** | 18.6 |
| *Cash flow* | | |
| Cash flow provided by operating activities | **226** | 168 |
| *Segment Results* | | |
| Regulated – Nuclear Generation | **75** | (118) |
| Regulated – Hydroelectric | **171** | 180 |
| Contracted Generation Portfolio | **78** | 77 |
| Total electricity generation business segments | **324** | 139 |
| Regulated – Nuclear Waste Management | **(33)** | (47) |
| Fair Hydro Trust | **4** | - |
| Other [1] | **276** | 7 |
| Income before interest and income taxes | **571** | 99 |

[1] For the three months ended March 31, 2018, includes the pre-tax gain on sale of the former Lakeview GS site.

[2] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 percent in April 2017.

[3] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Net income attributable to the Shareholder was $535 million for the first quarter of 2018, representing an increase of $471 million compared to the same quarter in 2017. Income before interest and income taxes was $571 million for the first quarter of 2018, representing an increase of $472 million compared to the same quarter in 2017. The following summarizes the significant factors which contributed to the variance:

*Significant factors that increased income before interest and income taxes:*

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $210 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices. Further details can be found under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices*.
- Higher revenue of approximately $25 million, partially offset by an increase in fuel expense of $5 million, reflecting higher electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment.
- A pre-tax gain on the sale of the former Lakeview GS site of $273 million recognized in net income upon completion of the transaction in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Sale of Lakeview Site*.
- Higher earnings of $14 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

*Significant factors that reduced income before interest and income taxes:*

- Higher depreciation and amortization expenses of $19 million, mainly due to new assets in service in the Regulated – Nuclear Generation segment.
- Higher OM&A expenses of $14 million, mainly reflecting higher services and materials costs associated with planned outages at the nuclear stations.
- Lower hydroelectric incentive mechanism payments of $7 million in the Regulated – Hydroelectric segment.

Net interest expense for the first quarter of 2018 was comparable with the same quarter in 2017.

Income tax expense increased by $1 million in the first quarter of 2018, compared to the same quarter in 2017. The increase due to higher income before taxes was largely offset by both a higher amount of deferred income tax expense recorded as a regulatory asset, and a reduction in income taxes due to a refundable tax credit of $86 million that lowered the effective tax rate in the first quarter of 2018.

## Recent Developments

OEB's Payment Amounts Order on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process, with an effective date for the new base regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for OPG's regulated facilities, the basis for inputs into the hydroelectric incentive mechanism formula, and the elements of the nuclear revenue requirement. Pursuant to the OEB's decision, the new base regulated prices for the regulated hydroelectric facilities for each of the years 2017 to 2021 are determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using an approved formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of operating costs and a return of and on invested capital,

reduced by a stretch factor amount. Consistent with the requirement of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated price is smoothed, with a portion of the approved nuclear revenue requirements for the 2017-2021 period deferred for future collection in the Rate Smoothing Deferral Account. The difference between the non-deferred portion of the annual nuclear revenue requirement, calculated by multiplying the approved nuclear base regulated price determined under rate smoothing and the approved forecast of OPG's nuclear electricity production, and the total approved nuclear revenue requirement determines the amount deferred for future collection. Further details on OPG's December 2017 decision can be found in OPG's 2017 annual MD&A in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

To reflect management's best estimate of the impact of the OEB's decision, in the fourth quarter of 2017, OPG recorded incremental net revenue for the June 1, 2017 to December 31, 2017 interim period based on the draft payment amounts order it submitted to the OEB on January 17, 2018 to reflect the December 2017 decision's findings. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 interim period revenue shortfall based on proposed new regulated prices, net of a regulatory liability for the Rate Smoothing Deferral Account.

On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices for OPG's regulated facilities, with an implementation date of March 1, 2018. For the regulated hydroelectric facilities, the OEB approved the base regulated prices as calculated by OPG in the draft payment amounts order for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period, based on the approved incentive regulation formula and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and published indices.

For the nuclear facilities, the OEB approved the 2017-2021 revenue requirements as submitted by OPG in the draft payment amounts order, with minor adjustments. The OEB also made certain adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices for the June 1, 2017 to December 31, 2017 period and each of the years 2018 to 2021 submitted in the draft payment amounts order. Pursuant to the final payment amounts order, no amounts will be deferred in the Rate Smoothing Deferral Account for 2017 or 2018, with approximately $500 million to be deferred over the 2019-2021 period. Parties to OPG's application were given an opportunity to review and comment on the draft payment amounts order prior to the OEB's issuance of the final payment amounts order.

The OEB's adjustments to OPG's rate smoothing proposal and resulting nuclear base regulated prices in the final payment amounts order resulted in a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017, largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017. The combined effect of these reversals did not have a material impact on the results of operations for the first quarter of 2018.

In addition, for the period from March 1, 2018 to December 31, 2020, the final payment amounts order authorized interim period shortfall riders to collect the revenue shortfall for the June 1, 2017 to February 28, 2018 period based on the newly approved base regulated prices. The order established separate rate riders for the March 1, 2018 to December 31, 2020 period to recover variance and deferral account balances approved in the application. As the interim period shortfall riders and the variance and deferral account riders will collect amounts previously recorded as regulatory assets, they will contribute to improved cash flow from operations but are not expected to have a material impact on net income.

The OEB's final payment amounts order authorized the following regulated prices for electricity generated from OPG's nuclear and regulated hydroelectric facilities for the 2017-2021 period, effective June 1, 2017:

| *($/MWh)* | **2017 June 1 to December 31** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **Regulated – Nuclear Generation** | | | | | |
| Base regulated price [1] | 77.96 | 78.64 | 77.00 | 85.00 | 89.70 |
| Interim period shortfall rider [1] | - | 2.89 | 7.71 | 5.64 | - |
| Variance and deferral account rate rider [2] | - | 1.05 | 2.79 | 2.04 | - |
| | 77.96 | 82.58 | 87.50 | 92.68 | 89.70 |
| **Regulated – Hydroelectric** | | | | | |
| Base regulated price [1, 3] | 41.67 | 42.05 | n/a | n/a | n/a |
| Interim period shortfall rider [1] | - | 0.13 | 0.35 | 0.24 | - |
| Variance and deferral account rate rider [2] | - | 0.52 | 1.44 | 1.01 | - |
| | 41.67 | 42.70 | n/a | n/a | n/a |

[1] As part of the payment amounts order process, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018, over the March 1, 2018 to December 31, 2020 period. The revenue shortfall was recorded as a regulatory asset in the fourth quarter of 2017 and the first quarter of 2018.

[2] Consistent with the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the next set of variance and deferral account balances, which may result in additional variance and deferral account riders prospectively over the period, depending on the outcome of the application.

[3] Base regulated prices for the regulated hydroelectric facilities for the 2019-2021 period will be determined annually before the beginning of each year using the OEB-approved incentive regulation formula and OEB-published inflation indices.

Darlington Refurbishment

In early May 2018, OPG completed the second major segment of the Unit 2 refurbishment of the Darlington GS, the removal of existing reactor components, and has transitioned into the third major segment, the installation and reassembly of new reactor components.

Planning activities for the refurbishment of Unit 3 of the Darlington GS continue. In February 2018, the Government of Ontario confirmed its commitment to proceed with the Unit 3 refurbishment. The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Payment of Dividend to Shareholder

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

Sale of Lakeview Site

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale, and is working with the Ontario Ministry of Finance to finalize the amount. In accordance with the Shareholder Resolution, approximately 67 acres of the site will be transferred to the City of Mississauga by the purchaser, for parkland, institutional, and cultural uses.

## Electricity Generation

Electricity generation for the three months ended March 31, 2018 and 2017 was as follows:

| | Three Months Ended March 31 | |
|---|---|---|
| *(TWh)* | **2018** | **2017** |
| Regulated – Nuclear Generation | **10.4** | 10.0 |
| Regulated – Hydroelectric | **7.7** | 8.0 |
| Contracted Generation Portfolio [1] | **0.7** | 0.6 |
| Total OPG electricity generation | **18.8** | 18.6 |
| Total electricity generation by other generators in Ontario [2] | **19.1** | 18.6 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation increased by 0.2 TWh during the first quarter of 2018, compared to the same quarter in 2017. This was due to higher electricity generation of 0.4 TWh from the Regulated – Nuclear Generation segment and 0.1 TWh from the Contracted Generation Portfolio, partially offset by lower electricity generation of 0.3 TWh from the Regulated – Hydroelectric segment.

The increase in electricity generation from the Regulated – Nuclear segment was primarily due to fewer planned outage days at the Darlington GS. The lower electricity generation from the Regulated – Hydroelectric segment was primarily due to lower water flows on the northwestern and eastern Ontario river systems.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the first quarter of 2018, Ontario's electricity demand as reported by the IESO was 35.0 TWh compared to 34.3 TWh for the same quarter in 2017, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario continued to be prevalent during first quarter of 2018, resulting in total forgone hydroelectric generation for OPG of 0.8 TWh, which was comparable to the same quarter in 2017. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 0.8 TWh in the first quarter of 2018, which was comparable to the same quarter in 2017. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

### Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed further in the section, *Highlights* under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices* and OPG's 2017 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 7.2 cents per kilowatt hour (¢/kWh) during the first quarter of 2018, compared to 5.8 ¢/kWh during the same quarter in 2017. The increase in the average sales price primarily reflected the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, partially offset by a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall to reflect the March 2018 payment amounts order. While the reversal of the regulatory liability for the Rate Smoothing Deferral Account that also resulted from the issuance of the March 2018 payment amounts order largely offset the revenue and income impact of the partial reversal of the June 1, 2017 to December 31, 2017 revenue shortfall regulatory asset, it did not impact the average sales price for the first quarter of 2018, as amounts deferred under rate smoothing are not included in the calculation of the average sales price until the period they are settled with ratepayers.

The average sales price for the Regulated – Hydroelectric segment was 4.2 ¢/kWh during each of the first quarters of 2018 and 2017. The average sales price was comparable in these periods as the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order was offset by lower revenue under the hydroelectric incentive mechanism in the first quarter of 2018.

### Cash Flow from Operations

Cash flow provided by operating activities for the three months ended March 31, 2018 was $226 million, compared to $168 million for the same period in 2017. The increase was mainly due to higher non-generation revenue cash receipts, lower expenditures on fixed asset removal and nuclear waste management activities, and lower income tax instalments.

### Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the twelve months ended March 31, 2018 was 11.5 percent, compared to 7.6 percent for the twelve months ended December 31, 2017. The increase in ROE Excluding AOCI was primarily due to higher net income attributable to the Shareholder as a result of increased revenue reflecting the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and the gain on the sale of the former Lakeview GS site recorded in the first quarter of 2018. ROE Excluding AOCI for these periods also reflected the after-tax gain of $283 million on the sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017. The gains on the sale of the former Lakeview GS site and the head office premises and associated parking facility, including the effect of the associated special dividend authorized in March 2018, together with the associated income tax effects of these transactions, contributed approximately 4.9 percent to ROE Excluding AOCI for the twelve months ended March 31, 2018 and approximately 2.5 percent for the twelve months ended December 31, 2017.

### Enterprise Total Generating Cost per Megawatt Hour

The Enterprise TGC per megawatt hour (MWh) was $49.84 for the three months ended March 31, 2018, compared to $47.86 for the same period in 2017. The increase was mainly a result of higher OM&A expenses before the impact of regulatory variance and deferral accounts and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

### Nuclear Total Generating Cost per Megawatt Hour

The Nuclear TGC per MWh was $70.90 for the three months ended March 31, 2018, compared to $69.87 for the same period in 2017. The increase in Nuclear TGC per MWh was primarily due to higher OM&A expenses before the impact of regulatory variance and deferral account and higher sustaining capital expenditures, partially offset by higher nuclear electricity generation.

### Hydroelectric Total Generating Cost per Megawatt Hour

The Hydroelectric TGC per MWh was $20.42 for the three months ended March 31, 2018, compared to $19.79 for the same period in 2017. The increase in the Hydroelectric TGC per MWh was primarily due to the decrease in hydroelectric electricity generation.

ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP, and should not be considered alternative measures to net income or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

## CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2017 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2017 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

### Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Public Safety

To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement. For 2017, the annual public doses resulting from the Darlington GS operations and the Pickering Nuclear GS (Pickering GS) operations were 0.7 μSv and 1.8 μSv, respectively, which is approximately 0.1 percent and 0.2 percent of the annual legal limit of 1,000 μSv, respectively.

Electricity Generation Production and Reliability

The status updates for OPG's electricity generation portfolio as of March 31, 2018 are summarized below:

- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. As previously announced, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In June 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. In August 2017, OPG submitted a ten-year licence renewal application to the CNSC in line with the plan to extend commercial operation to December 31, 2024 and place the station in a safe storage state in 2028. The first public hearing for the Pickering GS licence renewal application took place on April 4, 2018 and provided an opportunity for OPG to present its submission to the CNSC that outlined how the Pickering GS meets technical requirements and is qualified to continue operations. The final set of public hearings will take place between June 26 and June 28, 2018. Based on the evidence and documentation submitted to the CNSC, OPG continues to believe it is well positioned to obtain a licence renewal that would support its extended operations plan for the Pickering GS to 2024.

- In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. On February 7, 2018, following public hearings in April 2017, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

- During the first quarter of 2018, OPG completed the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump hydroelectric GS to ensure reliable unit operation for approximately the next 20 years, as well as the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which increased the station's generating capacity by 8 MW.

- Definition phase work for the frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 hydroelectric GS and the overhaul and upgrade of the R.H. Saunders hydroelectric GS units commenced during the first quarter of 2018.

- As part of the process to decommission the Nanticoke GS, OPG safely demolished the station's stacks in February 2018. The removal of the powerhouse and associated structures is in progress. A competitive bidding process for the demolition of the Lambton GS is continuing, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The costs of the decommissioning activities are charged to a previously established decommissioning provision.

Environmental Performance

In February 2018, the CNSC released sampling results from its 2017 independent environmental monitoring program, which confirmed that the public and environment around the Pickering GS are protected and that there are no expected health impacts. Samples were collected in publicly accessible areas outside the Pickering GS site perimeter and included air, lake water, soil, and wild vegetation. Samples of food were also taken from a local farm near the Pickering GS.

In the first quarter of 2018, the Government of Canada introduced legislation to amend the *Fisheries Act* (Bill C-68) and to replace the *Canadian Environmental Assessment Act, 2012* with a more comprehensive *Impact Assessment Act* (Bill C-69). If passed by Parliament, this legislation could introduce new regulatory requirements to further protect fish and fish habitat, and for assessing designated projects. OPG is reviewing the proposed changes and exploring opportunities to mitigate any associated risks.

Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2017 annual MD&A.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

In March 2018, the Employee Assistance Society of North America awarded OPG the annual Corporate Award of Excellence. These awards are given to organizations that showcase the excellence, innovation and impact of employee assistance programs in the workplace with a view to enhance employee well-being and support a healthy and productive working environment. OPG was recognized for its commitment to an organizational culture that values safety and good mental health as critical components of the organization's success.

## Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of March 31, 2018 are outlined below.

| Project | Capital expenditures | | Approved budget | Expected in-service date | Current status |
|---|---|---|---|---|---|
| *(millions of dollars)* | Year-to-date | Life-to-date | | | |
| Darlington Refurbishment | 241 | 4,675 | 12,800 [1] | First unit - 2020<br>Last unit - 2026 | The removal of existing Unit 2 reactor components was completed in early May 2018, with the installation of new components commencing thereafter. Planning activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and to the $12.8 billion budget. |
| Ranney Falls Hydroelectric GS | 8 | 36 | 77 | 2019 | Construction is continuing in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed. Turbine and generator unit fabrication is in progress. The project is tracking on schedule and on budget. |
| Nanticoke Solar Facility | 5 | 8 | 107 | 2019 | Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019. |
| Deep Geologic Repository (DGR) for Low and Intermediate Level Radioactive Waste (L&ILW) | - [2] | 208 [2] | | | In August 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is continuing to work on a response to this information request. |

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS. Project costs that do not meet capitalization criteria are charged to OM&A expenses in the period incurred.

[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the prerequisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

OPG commenced the refurbishment of the first unit, Unit 2, in October 2016. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in the first half of 2017, signifying the completion of the first major segment of the Unit 2 refurbishment.

The second major segment included the disassembly and removal of the existing reactor components. In early May 2018, OPG completed the removal of the reactor components, which included end fittings, pressure tubes, and calandria tubes, signifying the completion of the second major segment of the Unit 2 refurbishment.

The Unit 2 refurbishment has now transitioned into the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. Construction activities on the Heavy Water Storage and Drum Handling Facility are continuing.

In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of the second unit at the Darlington GS, Unit 3. In March 2018, OPG's Board of Directors approved the funding to complete planning and prerequisite activities for the Unit 3 refurbishment. The planning activities are progressing in accordance with the overall project schedule. OPG is ensuring that lessons learned from the Unit 2 refurbishment are appropriately incorporated into the Unit 3 refurbishment. OPG is also entering into commitments to procure major components that require long lead times. The prerequisite activities have commenced, with the Unit 3 refurbishment execution expected to commence upon the return to service of Unit 2. As of March 31, 2018, $137 million has been invested in planning and prerequisite activities related to the Unit 3 refurbishment.

The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues in the expanded forebay, powerhouse and spillway area. Fabrication of the sectional gates and two head gates has been completed, with assembly and site delivery in progress. Turbine and generator unit fabrication is also in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The project encompasses the construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation. Significant contracts for equipment and engineering construction services were executed and site preparation commenced in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million. The project is included in the Contracted Generation Portfolio segment.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been

reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to OPG's Western Waste Management Facility (WWMF) in Kincardine, Ontario.

Before the CNSC can make licensing decisions for the proposal, an EA must be conducted. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act* as well as the project specific Environmental Impact Statement Guidelines. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, with further information provided in May 2017 at the request of the CEAA. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the EA process and advised that a draft report and updated terms and conditions would be prepared for public review.

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the SON's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

## Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices.

The OEB's December 2017 decision and March 2018 payment amounts order establishing new regulated prices effective June 1, 2017 provide substantial price certainty for the regulated business up to 2021. While the OEB set costs for determining the new regulated prices below OPG's forecasted levels, including through the use of stretch factors under incentive ratemaking, the new regulated prices will result in a substantial increase in revenue and net income compared to the previously approved prices.

To further improve the financial strength of the regulated operations, OPG continues to focus on optimizing operational performance and outage plans across the generating fleet and pursue further efficiency improvements in the Company's cost structure and operating model. This includes continuing to progress the multi-year OPG25 initiative, which involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operation in 2024.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure of 45 percent equity and 55 percent debt maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Consistent with the OEB's December 2017 decision, later in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance as at December 31, 2017 and the balances accumulated between December 31, 2015 and December 31, 2017 in other variance and deferral account balances. If approved by the OEB, recovery of these balances would contribute to improved cash flow from operations.

Ensuring Availability of Cost Effective Funding

In April 2018, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of Indigenous communities. In the first quarter of 2018, the Dictionary of Moose Cree, an OPG-supported project that preserves the unique language and culture of the Moose Cree First Nation, was recognized by the Lieutenant Governor of Ontario. The language initiative was funded by OPG as a cultural project under the 2010 Amisk-oo-skow Agreement between OPG and the Moose Cree First Nation.

OPG's commitment in the area of Indigenous relations includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements and other joint projects. In addition to the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River, OPG is currently working with the Kiashke Zaaging Anishinaabek (KZA), also known as the Gull Bay First Nation, to construct a new renewable micro grid that will utilize solar generation, battery storage, and micro grid control technology to reduce the community's reliance on diesel generation. As the lead developer of the project, OPG will work with several collaborators to construct the micro grid on KZA reserve land. Upon completion, the micro grid will be transferred to KZA for ownership and operation. The micro grid project is OPG's fifth development project in partnership with an Indigenous community.

OPG is committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2018, this includes continuing to track the implementation of the Indigenous Business Engagement Initiative launched in 2017 to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG, and continuing to identify ways to increase the Indigenous representation in OPG's workforce. Recruitment initiatives include the launch of the Indigenous Opportunities in Nuclear program in the first quarter of 2018 using the Darlington Refurbishment project as a catalyst, and the continuing development of a dedicated Indigenous recruitment and retention strategy.

## Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of the Company's applications for regulated prices to the OEB.

In 2018, the full-year effect of the new regulated prices established by the OEB's December 2017 decision and March 2018 payment amounts order will contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results. An improvement in cash flow from operating activities during the remainder of 2018, compared to 2017, is also expected, as OPG begins to collect revenue from the IESO based on new regulated prices as of March 1, 2018. The Fair Hydro Trust segment will also modestly improve cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including purchases of subordinated debt issued by the Fair Hydro Trust (the Trust) to fund a portion of the Trust's acquisition of Investment Interests from the IESO, being the irrevocable right to recover Global Adjustment costs deferred by the IESO under the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act or the Act) and associated financing and other costs.

Several OEB-authorized regulatory variance and deferral accounts will continue to contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, these accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, which are reported in the Regulated – Nuclear Waste Management segment. Variations in rates of return for the funds based on financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, can be volatile and cause fluctuations in the Company's income in the near term. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position. As at March 31, 2018, the Decommissioning Segregated Fund was overfunded by approximately 26 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the current ONFA reference plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results include the earnings from the Fair Hydro Trust segment, primarily related to interest income from the Trust. Management expects that these earnings will increase in 2018 as additional Investment Interests are acquired. OPG's involvement as the Financial Services Manager under the Fair Hydro Act is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A shares to partially fund OPG's purchases of the Trust's subordinated debt, partially offset by the impact of incremental earnings from the Trust.

## ENVIRONMENTAL, SOCIAL, GOVERNANCE, AND SUSTAINABILITY

OPG's Darlington and Pickering nuclear generating stations and renewable fleet of hydroelectric generating stations produce clean, reliable electricity with virtually no greenhouse gas emissions. However, OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the Company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements, and is continuing to work with stakeholders to better define adaptation requirements.

OPG has established an Environmental, Social, Governance (ESG), and Sustainability steering committee consisting of a diverse group of representatives from various disciplines within the Company. The mandate of the committee is to evaluate the potential impact of environmental issues on the Company, oversee the development of a formal climate change strategy, assess and monitor the evolution of climate-related risks, and develop associated financial reporting disclosures.

OPG is in the process of developing its ESG and Sustainability framework to best reflect and disclose information that is meaningful to stakeholders. OPG plans to structure its ESG and Sustainability framework around four core themes:

- **Metrics and targets** to assess and manage relevant climate-related risks and opportunities;
- **Risk management** processes to identify, assess and manage climate-related risks;
- **Strategy** for incorporating climate change impacts into business planning and decision-making; and
- **Governance** for integrating the climate change strategy in the business.

In developing its ESG and Sustainability framework, OPG expects to leverage industry-specific and other emerging guidance on best practices related to ESG and Sustainability reporting and continues to monitor the Canadian Securities Administrators' project to review the disclosures of risks and financial impacts associated with climate change.

## DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

### Regulated – Nuclear Generation Segment

| *(millions of dollars) (unaudited)* | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Revenue | **880** | 652 |
| Fuel expense | **73** | 68 |
| Gross margin | **807** | 584 |
| Operations, maintenance and administration | **604** | 589 |
| Depreciation and amortization | **121** | 107 |
| Property taxes | **7** | 6 |
| Income (loss) before interest and income taxes | **75** | (118) |

Income before income interest and income taxes from the segment increased by $193 million during the first quarter of 2018, compared to the same quarter in 2017. The increase in earnings was primarily due to an increase in revenue of $228 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices, effective June 1, 2017. The higher earnings were also partially due to an increase in electricity generation of 0.4 TWh during the first quarter of 2018, compared to the same quarter in 2017, which contributed approximately $25 million to the year-over-year increase in revenue.

The increase in OM&A expenses of $15 million in the first quarter of 2018, compared to the same quarter in 2017, partially offset the increase in segment earnings. The increase in OM&A expenses was primarily due to higher services and materials costs associated with major planned outages.

Higher depreciation and amortization expenses of $14 million in the first quarter of 2018 were mainly due to new assets in service.

In the fourth quarter of 2017, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 to December 31, 2022 for Units 1 and 4 and to December 31, 2024 for Units 5 to 8, and recorded a corresponding change in the nuclear asset retirement obligation and associated asset retirement costs capitalized as part of the carrying value of property, plant and equipment, effective December 31, 2017. The change in these end-of-life assumptions took into account technical assessments completed to date as part of OPG's plan to extend the commercial operation of the Pickering GS to 2024 and the safety case reflected in the Pickering GS licence renewal application submitted to the CNSC in 2017. The decrease in depreciation expense associated with the change in these end-of-life assumptions in the first quarter of 2018 was offset by the impact of regulatory variance and deferral accounts, including a new deferral account proposed by OPG in its December 2017 accounting order application to the OEB and subsequently authorized by the OEB on an interim basis pending a final decision on the application.

The Unit Capability Factors for the Darlington GS and Pickering GS were as follows:

| | Three Months Ended March 31 | |
|---|---|---|
| | **2018** | **2017** |
| Unit Capability Factor *(%)* [1] | | |
| Darlington GS | **96.5** | 85.3 |
| Pickering GS | **74.5** | 78.5 |

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a lower number of planned outage days at the station in the first quarter of 2018.

The decrease in the Unit Capability Factor at the Pickering GS in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of planned outage days in the cyclical maintenance schedule at the station in the first quarter of 2018.

**Regulated – Nuclear Waste Management Segment**

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars) (unaudited)* | **2018** | **2017** |
| Revenue | **33** | 27 |
| Operations, maintenance and administration | **33** | 29 |
| Accretion on nuclear fixed asset removal and nuclear waste management liabilities | **243** | 234 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(210)** | (189) |
| Loss before interest and income taxes | **(33)** | (47) |

Earnings from the segment improved by $14 million in the first quarter of 2018, compared to the same quarter in 2017. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The year-over-year increase in earnings from the Nuclear Segregated Funds was primarily due to the growth rate in the present value of the underlying funding liabilities per the current approved ONFA reference plan in effect since January 1, 2017, as both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position since the beginning of 2017 and were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2017 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The year-over-year increase in accretion expense on the Nuclear Liabilities was mainly due to a higher amount of accretion expense deferred in regulatory variance and deferral accounts in the first quarter of 2017, due to costs not included in the nuclear base regulated price in effect prior to the OEB's December 2017 decision.

## Regulated – Hydroelectric Segment

| *(millions of dollars) (unaudited)* | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Revenue | **356** | 363 |
| Fuel expense | **65** | 73 |
| Gross margin | **291** | 290 |
| Operations, maintenance and administration | **80** | 76 |
| Depreciation and amortization | **36** | 34 |
| Other losses | **4** | - |
| Income before interest and income taxes | **171** | 180 |

[1] During the three months ended March 31, 2018 and 2017, the Regulated – Hydroelectric segment revenue reflected incentive payments of $1 million and $8 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Income before interest and income taxes from the segment decreased by $9 million during the first quarter of 2018, compared to the same quarter in 2017. The decrease in earnings was primarily due to lower hydroelectric incentive mechanism payments, higher OM&A expenses as a result of increased maintenance work programs, and retirement of replaced equipment.

The above factors were partially offset by the increase in revenue of approximately $5 million in the first quarter of 2018 to reflect the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, effective June 1, 2017.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

| | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Hydroelectric Availability *(%)* | **87.3** | 89.5 |

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same period in 2017, primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

## Contracted Generation Portfolio Segment

| *(millions of dollars) (unaudited)* | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Revenue | **149** | 143 |
| Fuel expense | **17** | 14 |
| Gross margin | **132** | 129 |
| Operations, maintenance and administration | **41** | 39 |
| Depreciation and amortization | **20** | 19 |
| Accretion on fixed asset removal liabilities | **2** | 2 |
| Property taxes | **1** | 2 |
| Income from investments subject to significant influence | **(10)** | (10) |
| Income before interest and income taxes | **78** | 77 |

Income before interest and income taxes from the segment in the first quarter of 2018 was comparable to the same quarter in 2017.

The increase in gross margin of $3 million in the first quarter of 2018 was primarily due to revenue from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017. The increase in OM&A expenses of $2 million in the first quarter of 2018 reflected higher station expenditures at the Lennox GS.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

| | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Hydroelectric Availability *(%)* | **80.1** | 83.6 |
| Thermal EFOR *(%)* | **0.3** | 12.6 |

The Hydroelectric Availability decreased in the first quarter of 2018, compared to the same quarter in 2017, primarily due to a higher number of planned outage days as a result of the overhaul and upgrade of Unit 2 of the Little Long GS on the Lower Mattagami River.

The lower Thermal EFOR in the first quarter of 2018, compared to the same quarter in 2017, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage in the first quarter of 2017.

## Fair Hydro Trust Segment

| *(millions of dollars) (unaudited)* | Three Months Ended March 31 2018 | 2017 |
|---|---|---|
| Earnings from Fair Hydro Trust | **4** | - |
| Income before interest and income taxes | **4** | - |

The Fair Hydro Trust was established in December 2017 as the financing entity contemplated by the Fair Hydro Act, for the purpose of acquiring Investment Interests from the IESO. In order for the Trust to finance such acquisitions, it incurs senior debt from capital markets and subordinated debt from OPG. The Company consolidates the financial results of the Trust in accordance with US GAAP.

In March 2018 and April 2018, the Trust purchased Investment Interests from the IESO in the amount of $460 million and $149 million, respectively. Fifty-one percent of the funding requirements for each acquisition totalling approximately $311 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent totalling approximately $298 million was funded through the following sources:

- the Province provided 44 percent of the funding requirements for each acquisition, or a total of $268 million, through equity injections in OPG in exchange for approximately 6.1 million non-voting Class A shares at a price of $43.74 per share; and
- OPG provided five percent of the funding requirements, or $30 million.

Earnings from Fair Hydro Trust were $4 million during the first quarter of 2018, primarily due to net interest income for the period.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements.

## LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's purchases of subordinated debt issued by the Fair Hydro Trust.

Changes in cash, cash equivalents and restricted cash for the three months ended March 31, 2018 and 2017 were as follows:

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars) (unaudited)* | **2018** | **2017** |
| Cash, cash equivalents and restricted cash, beginning of period | **234** | 186 |
| Cash flow provided by operating activities | **226** | 168 |
| Cash flow used in investing activities | **(604)** | (413) |
| Cash flow provided by financing activities | **472** | 279 |
| Net increase in cash, cash equivalents and restricted cash | **94** | 34 |
| Cash, cash equivalents and restricted cash, end of period | **328** | 220 |

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

### Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the first quarter of 2018 increased by $191 million compared to the same quarter in 2017. The increase in cash flow used in investing activities was primarily due to the Trust's acquisition of Investment Interest from the IESO in March 2018, partially offset by the receipt of proceeds from the sale of the former Lakeview GS site in March 2018.

### Financing Activities

As at March 31, 2018, short-term debt outstanding was $260 million, consisting of $100 million of commercial paper outstanding under OPG's commercial paper program and $160 million of commercial paper outstanding under Lower Mattagami Energy Limited Partnership's commercial paper program.

As at March 31, 2018, long-term debt outstanding was $6,896 million, including $263 million due within one year and including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets. This included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $836 million as at March 31, 2018.

During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving senior warehouse facility agreement expiring in December 2019. As at March 31, 2018, there were outstanding senior notes of $336 million under this credit facility, $235 million of which was used to finance 51 percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in March 2018. An additional $76 million was issued under the credit facility in April 2018 to finance fifty-one percent of the Trust's funding requirement for the acquisition of the Investment Interest from the IESO in April 2018.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust to provide a portion of the funding requirement for its first purchase of Investment Interest from the IESO in December 2017.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the Investment Interest acquisition in April 2018.

## BALANCE SHEET HIGHLIGHTS

The following section provides other highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

| *(millions of dollars) (unaudited)* | As At March 31 2018 | As At December 31 2017 |
|---|---|---|
| **Property, plant and equipment – net** | **21,515** | 21,322 |
| The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense. | | |
| **Nuclear fixed asset removal and nuclear waste management funds** *(current and non-current portions)* | **16,909** | 16,724 |
| The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities. | | |
| **Regulatory assets and liabilities – net** *(current and non-current portions)* | **6,773** | 6,637 |
| The increase was primarily due to the recognition of the interim period revenue shortfall for January and February 2018 reflecting the OEB's December 2017 decision and March 2018 payment amounts order on new regulated prices, and an increase in the regulatory asset for deferred income taxes. | | |
| **Long-term debt** *(current and non-current portions)* | **6,876** | 6,319 |
| The increase was primarily due to the issuance of senior notes payable to the OEFC of $600 million and the issuance of senior notes payable by the Fair Hydro Trust of $732 million. The increase was partially offset by debt repayments totalling $775 million. | | |
| **Fixed asset removal and nuclear waste management liabilities** | **20,639** | 20,421 |
| The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities | | |

### Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

## CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2017. A discussion of new accounting policies resulting from the adoption of new accounting standards effective January 1, 2018, recent accounting pronouncements, and changes in accounting estimates are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three months ended March 31, 2018 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2017 annual MD&A.

### Exemptive Relief for Reporting under US GAAP

In April 2018, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than IFRS, without becoming a Securities and Exchange Commission registrant. This exemption replaces the exemptive relief received by OPG from the OSC in February 2014. The exemption will terminate on the earliest of the following:

- January 1, 2024;
- the financial year that commences after OPG ceases to have activities subject to rate regulation; and
- the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

As a result of adopting US GAAP in 2011 as required by the FAA regulation, OPG's plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed the IFRS conversion project when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities.

## RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2017 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

### Risks to Achieving Operational Excellence

Proposed Asbestos Regulations

The Government of Canada is in the final stages of developing new regulations to prohibit the use of asbestos and products containing asbestos. The proposed *Prohibition of Asbestos and Asbestos Products Regulations* are expected to come into effect in 2018. The proposed regulations would prohibit the import, sale and use of asbestos and the manufacture, import, sale and use of products containing asbestos, with a limited number of exclusions. The use of asbestos and products containing asbestos that were installed prior to the proposed regulations coming into force would not be prohibited.

OPG is assessing the impact of the proposed regulations, particularly affecting the use of certain critical spare parts and existing inventory within the nuclear fleet which contain asbestos. These spare parts may be required to address an emergent condition or to complete a maintenance outage to return a unit to operation. OPG has provided submissions to Environment and Climate Change Canada and to the CNSC outlining the impacts of the proposed regulations on the Company's nuclear operations.

## Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

| | 2018 [1] | 2019 | 2020 |
|---|---|---|---|
| Estimated fuel requirements hedged [2] | 79% | 75% | 77% |

[1] Based on actual fuel requirements hedged for the three months ended March 31, 2018 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to US dollars. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at March 31, 2018, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the first quarter of 2018, the VaR utilization ranged between nil and $1 million.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at March 31, 2018 was $449 million, including $436 million to the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $13 million remaining exposure as at March 31, 2018, over 95 percent was with investment grade counterparties. Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

**RELATED PARTY TRANSACTIONS**

Given that the Province owns all of the outstanding common shares and Class A shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO, and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As a wholly owned government business enterprise of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

| | Three Months Ended March 31 | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| *(millions of dollars) (unaudited)* | **Income** | **Expense** | **Income** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **4** | **-** | 4 | - |
| Services | **-** | **5** | 1 | 5 |
| Dividends | **2** | **-** | 2 | - |
| Province of Ontario | | | | |
| Change in Decommissioning Segregated Fund amount due to Province [1] | **-** | **(2)** | - | 163 |
| Change in Used Fuel Segregated Fund amount due to Province [1] | **-** | **(21)** | - | 217 |
| Hydroelectric gross revenue charge | **-** | **28** | - | 28 |
| ONFA guarantee fee | **-** | **-** | - | 2 |
| OEFC | | | | |
| Hydroelectric gross revenue charge | **-** | **38** | - | 38 |
| Interest expense on long-term notes | **-** | **37** | - | 41 |
| Income taxes, net of investment tax credits | **-** | **53** | - | 12 |
| IESO | | | | |
| Electricity related revenue | **1,232** | **-** | 1,067 | - |
| Fair Hydro Trust | **11** | **-** | - | - |
| | **1,249** | **138** | 1,074 | 506 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at March 31, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,439 million and $4,462 million, respectively.

The receivables, financing receivables, equity securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| *(millions of dollars) (unaudited)* | **March 31 2018** | **December 31 2017** |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO – Electricity related receivables | **436** | 354 |
| IESO – Fair Hydro Trust [1] | **7** | 7 |
| OEFC | **2** | - |
| PEC | **4** | 4 |
| Province of Ontario | **2** | 3 |
| Financing receivables | | |
| IESO – Fair Hydro Trust | **1,639** | 1,179 |
| Equity securities | | |
| Hydro One shares | **170** | 188 |
| Accounts payable and accrued charges | | |
| Hydro One | **-** | 1 |
| OEFC | **35** | 52 |
| Province of Ontario | **11** | 9 |
| IESO − Electricity related payables | **1** | 5 |
| IESO – Fair Hydro Trust | **1** | 3 |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,520** | 3,195 |

[1] Balance consists of unbilled cost recovery revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at March 31, 2018, the Nuclear Segregated Funds held $1,319 million of Province of Ontario bonds (December 31, 2017 – $1,502 million) and $1 million of Province of Ontario treasury bills (December 31, 2017 – $9 million). As at March 31, 2018, the registered pension fund did not hold Province of Ontario bonds or treasury bills (December 31, 2017 – $1 million of Province of Ontario treasury bills). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In March and April 2018, the Fair Hydro Trust purchased Investment Interests from the IESO for an exchange amount of $460 million and $149 million, respectively, which have been classified as financing receivables on OPG's unaudited interim consolidated balance sheets. The transactions were settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, residential, farm, small businesses and other eligible customers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust and principal on debt. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivables. The three-month overlap in 2021 is intended to cover the billing and collections lag from the introduction of the Clean Energy Adjustment.

As at March 31, 2018, OPG's unaudited interim consolidated balance sheets included approximately $7 million of unbilled cost recovery revenue from the IESO (December 31, 2017 – $7 million), primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interests to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Act is invalid or unconstitutional.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

## QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

| *(millions of dollars – except where noted)* *(unaudited)* | **March 31 2018** | **December 31 2017** | **September 30 2017** | **June 30 2017** |
|---|---|---|---|---|
| Revenue | **1,407** | **1,619** | **1,217** | **1,146** |
| Net income | **539** | **366** | **140** | **307** |
| Less: Net income attributable to non-controlling interest | **4** | **4** | **9** | **4** |
| Net income attributable to the Shareholder | **535** | **362** | **131** | **303** |
| **Earnings per share, attributable to the Shareholder *(dollars)*** | **$1.99** | **$1.41** | **$0.51** | **$1.18** |

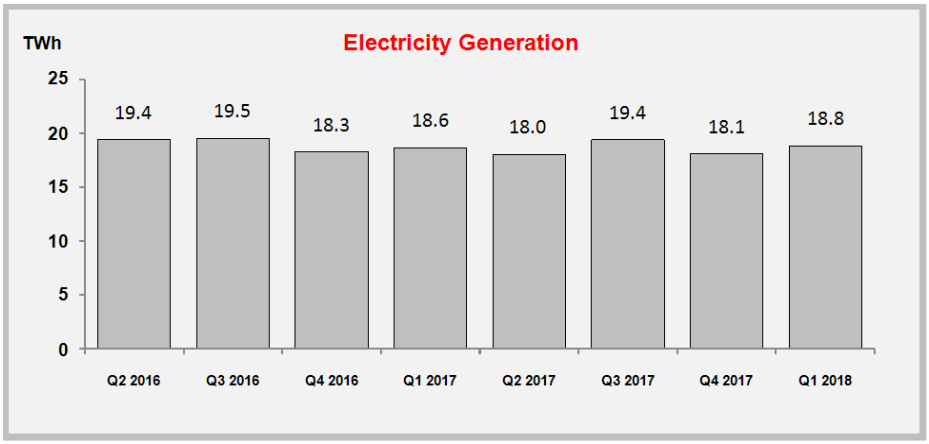
| *(millions of dollars – except where noted)* *(unaudited)* | **March 31 2017** | **December 31 2016** | **September 30 2016** | **June 30 2016** |
|---|---|---|---|---|
| Revenue | 1,176 | 1,388 | 1,400 | 1,387 |
| Net income (loss) | 68 | (8) | 198 | 135 |
| Less: Net income attributable to non-controlling interest | 4 | 5 | 4 | 3 |
| Net income (loss) attributable to the Shareholder | 64 | (13) | 194 | 132 |
| **Earnings per share, attributable to the Shareholder *(dollars)*** | $0.25 | ($0.05) | $0.76 | $0.51 |

## Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by OEB-authorized regulatory variance and deferral accounts (regulatory accounts).

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year but is not a significant driver of variability for full fiscal year results. The Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is continuing, has reduced electricity generation starting in the fourth quarter of 2016.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status.



## SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP, and therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

**(1) ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

| *(millions of dollars – except where noted) (unaudited)* | **Twelve Months Ended March 31 2018** | **December 31 2017** |
|---|---|---|
| ROE Excluding AOCI | | |
| Net income attributable to the Shareholder | **1,331** | 860 |
| Divided by: Average equity attributable to the Shareholder, excluding AOCI | **11,602** | 11,351 |
| **ROE Excluding AOCI *(percent)*** | **11.5** | 7.6 |

**(2) Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, the Fair Hydro Trust segment, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **2018** | **2017** |
| Enterprise TGC | | |
| Total OM&A expenses | **722** | 708 |
| Total fuel expense | **155** | 155 |
| Total capital expenditures | **359** | 408 |
| Less: Darlington Refurbishment capital and OM&A costs | **(259)** | (309) |
| Less: Other generation development project capital and OM&A costs | **(17)** | (17) |
| Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory accounts | **26** | (11) |
| Less: Nuclear fuel expense for non OPG-operated stations | **(15)** | (13) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **6** | 11 |
| Less: OM&A expenses ancillary to electricity generation business | **(4)** | (5) |
| Other adjustments | **-** | (2) |
| | **973** | 925 |
| Adjusted electricity generation *(TWh)* | | |
| Total OPG electricity generation | **18.8** | 18.6 |
| Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities | **0.7** | 0.7 |
| | **19.5** | 19.3 |
| **Enterprise TGC per MWh *($/MWh)*** [1] | **49.84** | **47.86** |

[1] Amounts may not calculate due to rounding.

**(3) Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **2018** | **2017** |
| Nuclear TGC | | |
| Regulated – Nuclear Generation OM&A expenses | **604** | 589 |
| Regulated – Nuclear Generation fuel expense | **73** | 68 |
| Regulated – Nuclear Generation capital expenditures | **313** | 366 |
| Less: Darlington Refurbishment capital and OM&A costs | **(259)** | (309) |
| Add (Less): Regulated – Nuclear Generation OM&A and fuel expenses deferred in (refundable through) regulatory accounts | **24** | (2) |
| Less: Nuclear fuel expense for non OPG-operated stations | **(15)** | (13) |
| Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business | **(2)** | (1) |
| Other adjustments | **(1)** | - |
| | **737** | 698 |
| Nuclear electricity generation *(TWh)* | **10.4** | 10.0 |
| **Nuclear TGC per MWh *($/MWh)*** [1] | **70.90** | 69.87 |

[1] Amounts may not calculate due to rounding.

**(4) Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Ranney Falls GS and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **2018** | **2017** |
| Hydroelectric TGC | | |
| Regulated – Hydroelectric OM&A expenses | **80** | 76 |
| Regulated – Hydroelectric fuel expense | **65** | 73 |
| Contracted Generation Portfolio OM&A expenses | **41** | 39 |
| Contracted Generation Portfolio fuel expense | **17** | 14 |
| Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures | **36** | 37 |
| Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs | **(18)** | (16) |
| Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio | **(44)** | (39) |
| Add (Less): Regulated – Hydroelectric OM&A and fuel expenses deferred in (refundable through) regulatory accounts | **2** | (9) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **6** | 11 |
| Other adjustments | **-** | (1) |
| | **185** | 185 |
| Adjusted hydroelectric electricity generation *(TWh)* | | |
| Regulated – Hydroelectric electricity generation | **7.7** | 8.0 |
| Contracted Generation Portfolio electricity generation | **0.7** | 0.6 |
| Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities | **0.7** | 0.7 |
| | **9.1** | 9.3 |
| **Hydroelectric TGC per MWh *($/MWh)*** [1] | **20.42** | 19.79 |

[1] Amounts may not calculate due to rounding.

**(5) Gross margin** is defined as revenue less fuel expense.

| | | |
|---|---|---|
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# ONTARIO POWER GENERATION INC.

# INTERIM CONSOLIDATED FINANCIAL STATEMENTS

**(unaudited)**

**MARCH 31, 2018**



# INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

| **Three Months Ended March 31**<br>*(millions of dollars except where noted)* | **2018** | **2017** |
|---|---|---|
| **Revenue** | **1,407** | 1,176 |
| Fuel expense | **155** | 155 |
| **Gross margin** | **1,252** | 1,021 |
| Operations, maintenance and administration | **722** | 708 |
| Depreciation and amortization | **186** | 167 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **247** | 238 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(210)** | (189) |
| Earnings from Fair Hydro Trust *(Note 16)* | **(4)** | - |
| Income from investments subject to significant influence | **(10)** | (10) |
| Property taxes | **9** | 11 |
| | **940** | 925 |
| **Income before other gains, interest and income taxes** | **312** | 96 |
| Other gains *(Note 19)* | **259** | 3 |
| **Income before interest and income taxes** | **571** | 99 |
| Net interest expense *(Note 5)* | **19** | 19 |
| **Income before income taxes** | **552** | 80 |
| Income tax expense *(Note 8)* | **13** | 12 |
| **Net income** | **539** | 68 |
| **Net income attributable to the Shareholder** | **535** | 64 |
| Net income attributable to non-controlling interest | **4** | 4 |
| **Basic and diluted earnings per share** *(dollars) (Note 14)* | **1.99** | 0.25 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

| **Three Months Ended March 31**<br>*(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| **Net income** | **539** | 68 |
| **Other comprehensive income, net of income taxes** *(Note 9)* | | |
| Reclassification to income of amounts related to pension and other post-employment benefits [1] | **3** | 3 |
| Reclassification to income of losses on derivatives designated as cash flow hedges [2] | **4** | 4 |
| Unrealized gain on equity securities [3] | **-** | 5 |
| Other comprehensive income for the period | **7** | 12 |
| **Comprehensive income** | **546** | 80 |
| **Comprehensive income attributable to the Shareholder** | **542** | 76 |
| Comprehensive income attributable to non-controlling interest | **4** | 4 |

[1] Net of income tax expenses of $1 million for each of the three months ended March 31, 2018 and 2017.

[2] Net of income tax expenses of $1 million for each of the three months ended March 31, 2018 and 2017.

[3] Net of income tax expense of nil and $1 million for the three months ended March 31, 2018 and 2017, respectively.

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

| **Three Months Ended March 31**<br>*(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| **Operating activities** | | |
| Net income | **539** | 68 |
| Adjust for non-cash items: | | |
| Depreciation and amortization | **186** | 167 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **247** | 238 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(210)** | (189) |
| Pension and other post-employment benefit costs *(Note 10)* | **99** | 113 |
| Deferred income taxes | **(6)** | 11 |
| Regulatory assets and regulatory liabilities | **(141)** | (28) |
| Other gains *(Note 19)* | **(257)** | (1) |
| Other | **(13)** | (4) |
| Expenditures on fixed asset removal and nuclear waste management | **(63)** | (76) |
| Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management | **23** | 22 |
| Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans | **(79)** | (88) |
| Distributions received from investments subject to significant influence | **12** | 14 |
| Net changes to other long-term assets and long-term liabilities | **43** | 38 |
| Net changes to non-cash working capital balances *(Note 17)* | **(154)** | (117) |
| **Cash flow provided by operating activities** | **226** | 168 |
| **Investing activities** | | |
| Acquisition of Fair Hydro Trust financing receivables | **(460)** | - |
| Proceeds from deposit note | **-** | 45 |
| Net proceeds from sale of property, plant and equipment | **273** | - |
| Investment in property, plant and equipment and intangible assets | **(417)** | (458) |
| **Cash flow used in investing activities** | **(604)** | (413) |
| **Financing activities** | | |
| Issuance of Class A shares *(Note 13)* | **202** | - |
| Issuance of OPG long-term debt *(Note 5)* | **600** | 200 |
| Repayment of OPG long-term debt | **(275)** | (50) |
| Issuance of Fair Hydro Trust long-term debt *(Note 5)* | **732** | - |
| Repayment of Fair Hydro Trust long-term debt | **(500)** | - |
| Distribution to non-controlling interest | **(4)** | (4) |
| Dividend to the Province's Consolidated Revenue Fund *(Note 18)* | **(283)** | - |
| Issuance of short-term debt | **1,295** | 589 |
| Repayment of short-term debt | **(1,295)** | (456) |
| **Cash flow provided by financing activities** | **472** | 279 |
| Net increase in cash, cash equivalents and restricted cash | **94** | 34 |
| **Cash, cash equivalents and restricted cash, beginning of period** | **234** | 186 |
| **Cash, cash equivalents and restricted cash, end of period** | **328** | 220 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| As at<br>*(millions of dollars)* | March 31<br>2018 | December 31<br>2017 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash, cash equivalents and restricted cash *(Note 3)* | **328** | 234 |
| Equity securities | **170** | 188 |
| Receivables from related parties | **452** | 369 |
| Nuclear fixed asset removal and nuclear waste management funds | **23** | 23 |
| Fuel inventory | **299** | 309 |
| Materials and supplies | **96** | 103 |
| Regulatory assets *(Note 4)* | **259** | - |
| Prepaid expenses | **196** | 192 |
| Income taxes recoverable | **10** | - |
| Other current assets | **98** | 146 |
| | **1,931** | 1,564 |
| **Property, plant and equipment** | **30,292** | 29,950 |
| Less: accumulated depreciation | **8,777** | 8,628 |
| | **21,515** | 21,322 |
| **Intangible assets** | **576** | 565 |
| Less: accumulated amortization | **440** | 432 |
| | **136** | 133 |
| **Other assets** | | |
| Nuclear fixed asset removal and nuclear waste management funds | **16,886** | 16,701 |
| Financing receivables | **1,639** | 1,179 |
| Long-term materials and supplies | **352** | 355 |
| Regulatory assets *(Note 4)* | **7,107** | 7,231 |
| Investments subject to significant influence | **307** | 309 |
| Other long-term assets | **32** | 28 |
| | **26,323** | 25,803 |
| | **49,905** | 48,822 |

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| *(millions of dollars)* | March 31 2018 | December 31 2017 |
|---|---|---|
| **Liabilities** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | **1,119** | 1,228 |
| Short-term debt *(Note 6)* | **260** | 260 |
| Deferred revenue due within one year | **9** | 12 |
| Long-term debt due within one year *(Note 5)* | **263** | 398 |
| Income taxes payable | **-** | 80 |
| Regulatory liabilities *(Note 4)* | **19** | - |
| | **1,670** | 1,978 |
| **Long-term debt** *(Note 5)* | **6,613** | 5,921 |
| **Other liabilities** | | |
| Fixed asset removal and nuclear waste management liabilities *(Note 7)* | **20,639** | 20,421 |
| Pension liabilities | **3,389** | 3,423 |
| Other post-employment benefit liabilities | **3,118** | 3,092 |
| Long-term accounts payable and accrued charges | **252** | 252 |
| Deferred revenue | **368** | 351 |
| Deferred income taxes | **917** | 879 |
| Regulatory liabilities *(Note 4)* | **574** | 594 |
| | **29,257** | 29,012 |
| **Equity** | | |
| Common shares *(Note 13)* | **5,126** | 5,126 |
| Class A shares *(Note 13)* | **721** | 519 |
| Retained earnings | **6,632** | 6,396 |
| Accumulated other comprehensive loss *(Note 9)* | **(279)** | (295) |
| **Equity attributable to the Shareholder** | **12,200** | 11,746 |
| Equity attributable to non-controlling interest | **165** | 165 |
| **Total equity** | **12,365** | 11,911 |
| | **49,905** | 48,822 |

# INTERIM CONSOLIDATED STATEMENTS OF SHAREHOLDER'S EQUITY (UNAUDITED)

| **Three Months Ended March 31**<br>*(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| **Common shares** *(Note 13)* | **5,126** | 5,126 |
| **Class A shares** *(Note 13)* | | |
| Balance at beginning of period | **519** | - |
| Issuance of Class A shares | **202** | - |
| Balance at end of period | **721** | - |
| **Retained earnings** | | |
| Balance at beginning of period | **6,396** | 5,534 |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **(9)** | - |
| Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings *(Note 2)* | **(7)** | - |
| | **6,380** | 5,534 |
| Net income attributable to the Shareholder | **535** | 64 |
| Dividend to the Province's Consolidated Revenue Fund *(Note 18)* | **(283)** | - |
| Balance at end of period | **6,632** | 5,598 |
| **Accumulated other comprehensive loss, net of income taxes** | | |
| Balance at beginning of period | **(295)** | (295) |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **9** | - |
| | **(286)** | (295) |
| Other comprehensive income | **7** | 12 |
| Balance at end of period | **(279)** | (283) |
| **Equity attributable to the Shareholder** | **12,200** | 10,441 |
| **Equity attributable to non-controlling interest** | | |
| Balance at beginning of period | **165** | 143 |
| Distribution to non-controlling interest | **(4)** | (4) |
| Income attributable to non-controlling interest | **4** | 4 |
| Balance at end of period | **165** | 143 |
| **Total equity** | **12,365** | 10,584 |

*See accompanying notes to the interim consolidated financial statements*

# NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three months ended March 31, 2018 and 2017

## 1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three months ended March 31, 2018 and 2017 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2017. All dollar amounts are presented in Canadian dollars.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2017 comparative amounts have been reclassified from financial statements previously presented to conform to the 2018 interim consolidated financial statement presentation.

### Use of Management Estimates

The preparation of interim consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

## 2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

### New Accounting Standards Effective in 2018

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

Effective January 1, 2018, OPG adopted Topic 606, including relevant practical expedients, utilizing the modified retrospective approach to implement the transition. No differences in the timing or amount of revenue recognition were identified as a result of the adoption of the new standard. The adoption of Topic 606 has required OPG to amend its accounting policy with respect to revenue recognition, as described below.

*Revenue from Contracts with Customers – Regulated Generation*

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the Ontario Energy Board (OEB) that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electrical System Operator (IESO). For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis based on regulated prices authorized by the OEB. OPG's performance obligation with respect to regulated generation is to supply electricity generated from its regulated nuclear and regulated hydroelectric facilities to the wholesale electricity market in Ontario. The Company has determined that this performance obligation is satisfied over time; OPG utilizes the output method under Topic 606 to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each unit of electricity generated and metered to the IESO. This methodology reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period. During interim rate periods authorized by the OEB, revenue is recognized on the basis of interim regulated prices set by the OEB. In instances where a subsequent OEB decision results in a difference between final regulated prices retroactively effective for the interim period and the interim regulated prices, OPG records the resulting adjustment to revenue in connection with that period based on the OEB's decision. Any resulting revenue shortfall in connection with the interim rate period is collected prospectively from the IESO in the manner authorized by the OEB. OPG's receivables in connection with electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

Regulated prices currently in effect for OPG's regulated nuclear and regulated hydroelectric generation were established by the OEB's December 2017 decision and March 2018 payment amounts order on OPG's 2016 application for new regulated prices for the 2017-2021 period. In the decision, the OEB set an effective date for the new base regulated prices of June 1, 2017. Pursuant to the decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices are determined using a formula that annually escalates the previously approved regulated prices, subject to some adjustments,

based on an industry-specific weighted inflation factor reflecting indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices are determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to *Ontario Regulation 53/05*, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years is based on the OEB-allowed level of operating costs including depreciation and amortization expenses and a return on rate base, less a stretch factor adjustment. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The difference between the non-deferred portion of the nuclear revenue requirement, calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. See Note 4 for further information on the March 2018 payment amounts order and the Rate Smoothing Deferral Account.

Base regulated prices in effect during the period January 1, 2017 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs (including depreciation and amortization expenses) for the regulated facilities for 2014 and 2015 and a return on rate base.

*Revenue from Contracts with Customers – Non-regulated Generation and Other Contract Revenue*

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. The IESO is the counterparty to all ESAs and other contractual arrangements that are currently in effect. As at December 31, 2017, most of OPG's operating non-regulated generating assets are subject to an ESA. As permitted by the practical expedient within Topic 606, revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis to the IESO as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity from the applicable facilities to Ontario's wholesale energy market. No portion of OPG's performance obligation remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts under each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration under each ESA is included in revenue only to the extent that it is probable that the amount will not be subject to significant reversal when the underlying uncertainty is resolved. OPG's receivables in connection with electricity generated from its non-regulated assets are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and mid-west regions of the United States. Under these arrangements, OPG's performance obligation is to either physically supply energy or provide capacity, depending on the contract, to a counterparty in a control area outside of Ontario. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income.

OPG also derives non-energy revenue under the terms of a lease arrangement and associated, non-lease agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, detritiation services and nuclear waste management services. Revenues under these associated agreements are recognized as services are provided or when products are delivered, therein satisfying OPG's performance obligation.

In addition, non-energy revenue includes isotope sales and other service revenues. Revenues from these activities are recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

*Revenue Recognition – Leasing Revenue*

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power related to the Bruce nuclear generating stations are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate rentals is recognized over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities are required to measure equity investments at fair value and recognize any changes in fair value in net income. The update is effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for securities is no longer available. Effective January 1, 2018, any unrealized gains and losses related to equity securities are recognized in net income instead of other comprehensive income.

As a result of the adoption of the new guidance, the unrealized cumulative after-tax loss of $9 million on AFS securities reported by OPG in Accumulated Other Comprehensive Income as at December 31, 2017 was reclassified to opening retained earnings as of January 1, 2018. There were no other impacts on OPG's consolidated financial statements upon adoption of the new guidance, other than to replace the accounting policy for AFS securities with a new policy for holdings of equity securities as described below.

*Equity Securities*

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized within other gains and losses in the consolidated statement of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at the transaction price.

Restricted Cash Disclosures

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows* (Topic 230): *Restricted* Cash (a consensus of the FASB Emerging Issues Task Force), which clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is effective for OPG's 2018 fiscal year, including interim periods, and is applied retrospectively. The changes in disclosures required under this update are reflected in the interim consolidated statements of cash flows and Note 3.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits* (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

Effective January 1, 2018, OPG adopted the new provisions of Topic 715. Adoption of these provisions did not impact OPG's consolidated financial statements, as OPG capitalized only the service cost component of

postretirement benefits costs prior to the adoption of the new guidance. Additionally, OPG previously included the service cost component of postretirement benefit costs with other compensation costs within Operating, maintenance and administration expenses in the consolidated statements of income, and did not show a subtotal of income from operations prior to the adoption of the new guidance. As such, the new guidance did not affect the presentation of OPG's consolidated financial statements nor result in changes in OPG's accounting policies.

Intra-entity Transfers of Assets Other than Inventory

In October 2016, the FASB issued ASU 2016-16, *Income Taxes* (Topic 740): *Intra-Entity Transfers of Assets Other than Inventory*, to amend existing guidance with respect to accounting for the income tax effects of intra-entity asset transfers within the consolidated group. Effective January 1, 2018, entities are required to recognize the income tax effects of all intra-entity asset transfers, with the exception of inventory, as soon as the transfer occurs. Previously, entities were required to defer recognition of such income tax effects until the asset was sold to a third party.

The update is effective for OPG beginning January 1, 2018 and is required to be applied on a modified retrospective basis. On adoption of the update, the Company recorded an adjustment reducing opening retained earnings by $7 million to reflect the associated deferred income tax liability resulting from the cumulative effect of OPG's transfer of assets, other than inventory, to the UMH Energy Limited Partnership (UMH) and the Lower Mattagami Energy Limited Partnership (LME) in prior years. Adoption of this update did not otherwise impact the Company's consolidated financial statements, other than through an addition to OPG's accounting policy for income taxes as described below.

*Income Taxes – Intra-entity Transfers of Non-inventory Assets*

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

**Recent Accounting Pronouncements Not Yet Adopted**

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under *Leases* (Topic 840). The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU (ASU No. 2018-200) wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company continues to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or have expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company has implemented a comprehensive project governance framework to oversee the transition to the new

leasing guidance, comprised of a Steering Committee, Implementation and Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. Management has commenced procedures to provide assurance over the completeness of the population of leasing arrangements identified for assessment against the new guidance. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

## 3. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash, cash equivalents and restricted cash include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Cash, cash equivalents, and restricted cash consist of the following:

| **As at**<br>*(millions of dollars)* | **March 31 2018** | **December 31 2017** |
|---|---|---|
| Cash and cash equivalents | **315** | 230 |
| Restricted cash | **13** | 4 |
| Total cash, cash equivalents and restricted cash | **328** | 234 |

Restricted cash represents the Fair Hydro Trust's (the Trust) cash on deposit that is subject to contractual restrictions of the Trust's Master Trust Indenture. All of the Trust's bank accounts are under the name and exclusive control of its indenture trustee. Amounts on deposit are restricted in purpose and the distribution of use is subject to the order of payment priority outlined in the Trust's Master Trust Indenture.

## 4. REGULATORY ASSETS AND REGULATORY LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and interveners on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017-2021 period and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's OEB-authorized regulatory variance and deferral accounts (regulatory accounts), with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. In January 2018, OPG submitted a draft payment amounts order to the OEB to reflect the December 2017 decision's findings.

In March 2018, the OEB issued the final payment amounts order on OPG's application for new regulated prices. With respect to variance and deferral accounts, the payment amounts order authorized OPG to collect, through rate riders on nuclear and regulated hydroelectric production, the approved amount of $305 million over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and December 31, 2020. Any shortfall or over-recovery of the approved balance due to differences between actual and forecast production is to be recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account authorized by the OEB.

Amortization of regulatory assets and regulatory liabilities for variance and deferral account balances approved for disposition in the OEB's March 2018 payment amounts order is recorded on a straight-line basis, effective March 1, 2018, based on the portion of the balances authorized to be collected during the applicable period.

The payment amount order set a rate smoothing approach and resulting nuclear base regulated prices effective June 1, 2017 such that no amounts are to be deferred in the Rate Smoothing Deferral Account for 2017 or 2018. Pursuant to the payment amounts order, approximately $500 million is to be deferred in the Rate Smoothing Deferral Account over the 2019-2021 period.

The approved rate smoothing approach and resulting nuclear base regulated prices represented an adjustment to the proposal in OPG's draft payment amounts order, which was the basis for management's best estimate of the increase in net revenue and corresponding increase in net regulatory assets recorded in the fourth quarter of 2017 related to the impact of the new regulated prices on the June 1, 2017 to December 31, 2017 period. To reflect the adjustment arising from the final payment amounts order, in the first quarter of 2018, OPG recorded a reduction of $67 million in the Interim Period Revenue Shortfall regulatory asset previously recognized as of December 31, 2017 and a reversal of the $63 million regulatory liability for the Rate Smoothing Deferral Account regulatory liability previously recognized as of December 31, 2017.

For the regulated hydroelectric facilities, the payment amounts order set base regulated prices for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period as calculated by OPG in the draft payment amounts order, based on the incentive regulation formula approved in the December 2017 decision and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and published indices.

The payment amounts order authorized separate rate riders on nuclear and regulated hydroelectric production for the collection of the June 1, 2017 to February 28, 2018 interim period revenue shortfall over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and December 31, 2020. The Interim Period Revenue Shortfall regulatory asset is reversed as these riders are collected.

The regulatory assets and regulatory liabilities recorded as at March 31, 2018 and December 31, 2017 are as follows:

| *(millions of dollars)* | **March 31 2018** | **December 31 2017** |
|---|---|---|
| Regulatory assets | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Pension and OPEB Cost Variance Account | **712** | 716 |
| Pension & OPEB Cash Versus Accrual Differential Deferral Account | **655** | 614 |
| Hydroelectric Surplus Baseload Generation Variance Account | **387** | 360 |
| Bruce Lease Net Revenues Variance Account | **127** | 121 |
| Other variance and deferral accounts | **124** | 124 |
| | **2,005** | 1,935 |
| Interim Period Revenue Shortfall | **612** | 544 |
| Pension and OPEB Regulatory Asset *(Note 10)* | **3,806** | 3,855 |
| Deferred Income Taxes | **943** | 897 |
| Total regulatory assets | **7,366** | 7,231 |
| Less: current portion | **259** | - |
| Non-current regulatory assets | **7,107** | 7,231 |
| Regulatory liabilities | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Hydroelectric Water Conditions Variance Account | **167** | 150 |
| Pension & OPEB Cash Payment Variance Account | **157** | 140 |
| Changes in Station End-of-Life Dates Deferral Account | **103** | 103 |
| Other variance and deferral accounts | **166** | 201 |
| Total regulatory liabilities | **593** | 594 |
| Less: current portion | **19** | - |
| Non-current regulatory liabilities | **574** | 594 |

As at March 31, 2018 and December 31, 2017, regulatory assets for other variance and deferral accounts included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Liability Deferral Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account, the Nuclear Development Variance Account, and the Fitness for Duty Deferral Account. As at March 31, 2018 and December 31, 2017, regulatory liabilities for other variance and deferral accounts included the amounts for the Capacity Refurbishment Variance Account, the Ancillary Services Net Revenue Variance Account, the Hydroelectric Incentive Mechanism Variance Account, the Income and Other Taxes Variance Account, and the SR&ED ITC Variance Account.

As at December 31, 2017, regulatory assets for other variance and deferral accounts also included amounts for the Rate Smoothing Deferral Account, which were reversed in the first quarter of 2018.

In January 2018, pursuant to an accounting order application filed by OPG in December 2017, the OEB authorized the establishment of a new Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018, on an interim basis, pending a final decision on the application. The purpose of the account is to record the revenue requirement impact of the changes to nuclear fixed asset removal and nuclear waste management liabilities and depreciation and amortization expenses resulting from the changes to the accounting end-of-life assumptions for OPG's Pickering nuclear generating stations implemented effective December 31, 2017. As of March 31, 2018, OPG recognized a regulatory liability of $31 million related to the balance in the deferral account, which is included in other variance and deferral accounts.

## 5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

| *(millions of dollars)* | **March 31 2018** | **December 31 2017** |
|---|---|---|
| Senior notes payable to the Ontario Electricity Financial Corporation | **3,520** | 3,195 |
| Medium Term Notes | **500** | 500 |
| UMH Energy Partnership project debt | **181** | 181 |
| PSS Generating Station Limited Partnership project debt | **245** | 245 |
| Lower Mattagami Energy Limited Partnership project debt | **1,595** | 1,595 |
| Fair Hydro Trust senior debt | **836** | 601 |
| Other | **19** | 19 |
| | **6,896** | 6,336 |
| Less: unamortized bond issuance fees | **(20)** | (17) |
| Less: amounts due within one year | **(263)** | (398) |
| Long-term debt | **6,613** | 5,921 |

In the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the Ontario Electricity Financial Corporation maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving warehouse facility agreement with an expiry date of December 2019. In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued to provide a portion of the funding requirement for the Trust's purchase of Investment Interest from the IESO in December 2017.

In March 2018, the Trust purchased an Investment Interest from the IESO in the amount of $460 million. Fifty-one percent of the funding requirement or approximately $235 million was financed by the Trust through the revolving warehouse facility, and the remaining 49 percent was funded through the issuance of subordinated debt to OPG. The outstanding balance of the revolving warehouse credit facility of $336 million has been classified as long-term debt as at March 31, 2018 reflecting the contractual terms of the facility agreement.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the balance of the revolving warehouse facility outstanding after the April 2018 Investment Interest acquisition from the IESO of $149 million, of which $76 million was funded through this facility.

During the first quarter of 2018, $275 million of OPG long-term debt and $500 million of Fair Hydro Trust long-term debt were repaid.

The following table summarizes the net interest expense for the three months ended March 31 :

| *(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| Interest on long-term debt [1] | **70** | 70 |
| Interest income | **(1)** | - |
| Interest capitalized to property, plant and equipment and intangible assets | **(44)** | (42) |
| Interest related to regulatory assets and liabilities [2] | **(6)** | (9) |
| Net interest expense | **19** | 19 |

[1] Excludes interest on Fair Hydro Trust senior debt and interest on OPG's debt attributed to funding a portion of OPG's purchase of the Trust's subordinated debt. These interest costs have been included in earnings from Fair Hydro Trust in the interim consolidated statements of income. Refer to Note 16 for further details.

[2] Includes interest to recognize the cost of financing related to regulatory accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account and, in 2018, the Impact Resulting from Changes to Pickering Station End-of life Dates (December 31, 2017) Deferral Account.

## 6. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches expiring in May 2022. There were no amounts outstanding under the bank credit facility as at March 31, 2018 and December 31, 2017. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at March 31, 2018 (December 31, 2017 – $100 million). The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately one percent and for less than one year in duration.

As at March 31, 2018, LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at March 31, 2018, there was $160 million of commercial paper outstanding under LME's commercial paper program (December 31, 2017 − $160 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at March 31, 2018 under the first tranche of LME's credit facility.

As at March 31, 2018, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $464 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at March 31, 2018, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the Portland Energy Centre.

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at March 31, 2018, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at March 31, 2018, total Letters of Credit of $15 million had been issued under these facilities.

## 7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at March 31, 2018 and December 31, 2017 consist of the following:

| As at<br>*(millions of dollars)* | March 31<br>2018 | December 31<br>2017 |
|---|---|---|
| Liability for nuclear used fuel management | **12,112** | 11,970 |
| Liability for nuclear decommissioning and nuclear low and intermediate level waste management | **8,185** | 8,107 |
| Liability for non-nuclear fixed asset removal | **342** | 344 |
| Fixed asset removal and nuclear waste management liabilities | **20,639** | 20,421 |

## 8. INCOME TAXES

OPG follows the liability method of tax accounting for all of its business segments and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Income tax expense in the first quarter of 2018 was reduced as a result of a refundable tax credit of $86 million arising on payment of the dividend during the quarter (see note 18), and a higher amount of deferred income tax expense recorded as a regulatory asset.

## 9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

| | Three Months Ended March 31, 2018 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | Unrealized Gains and Losses on Cash Flow Hedges | Pension and OPEB | Equity Securities | Total |
| AOCL, beginning of period | **(66)** | **(220)** | **(9)** | **(295)** |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **-** | **-** | **9** | **9** |
| | **(66)** | **(220)** | **-** | **(286)** |
| Amounts reclassified from AOCL | **4** | **3** | **-** | **7** |
| Other comprehensive income for the period | **4** | **3** | **-** | **7** |
| AOCL, end of period | **(62)** | **(217)** | **-** | **(279)** |

| (millions of dollars) | Three Months Ended March 31, 2017<br>Unrealized Gains and Losses on Cash Flow Hedges | Pension and OPEB | Equity Securities | Total |
|---|---|---|---|---|
| AOCL, beginning of period | (87) | (207) | (1) | (295) |
| Unrealized gain on equity securities | - | - | 5 | 5 |
| Amounts reclassified from AOCL | 4 | 3 | - | 7 |
| Other comprehensive income for the period | 4 | 3 | 5 | 12 |
| AOCL, end of period | (83) | (204) | 4 | (283) |

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three months ended March 31, 2018 and 2017 are as follows:

| (millions of dollars) | Amount Reclassified from AOCL<br>2018 | 2017 | Statement of Income Line Item |
|---|---|---|---|
| Amortization of losses from cash flow hedges | | | |
| Losses | **5** | 5 | Net interest expense |
| Income tax recovery | **(1)** | (1) | Income tax expense |
| | **4** | 4 | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses | **4** | 4 | See (1) below |
| Income tax recovery | **(1)** | (1) | Income tax expense |
| | **3** | 3 | |
| Total reclassifications for the period | **7** | 7 | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

## 10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended March 31, 2018 and 2017 are as follows:

| (millions of dollars) | Registered Pension Plans<br>2018 | 2017 | Supplementary Pension Plans<br>2018 | 2017 | Other Post-Employment Benefits<br>2018 | 2017 |
|---|---|---|---|---|---|---|
| *Components of Cost Recognized for the Period* | | | | | | |
| Current service costs | **83** | 68 | **2** | 1 | **20** | 17 |
| Interest on projected benefit obligation | **142** | 137 | **3** | 3 | **26** | 27 |
| Expected return on plan assets, net of expenses | **(205)** | (191) | **-** | - | **-** | - |
| Amortization of net actuarial loss [1] | **49** | 46 | **2** | 2 | **2** | - |
| Costs recognized [2] | **69** | 60 | **7** | 6 | **48** | 44 |

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended March 31, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $49 million (three months ended March 31, 2017 − $44 million).

[2] These pension and OPEB costs for the three months ended March 31, 2018 exclude the net reduction of costs of $25 million from the recognition of changes in the regulatory assets for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended March 31, 2017 − net addition of costs of $3 million).

## 11. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. OPG's electricity related accounts receivable from the IESO constituted of $436 million as at March 31, 2018 (December 31, 2017 − $354 million). The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at March 31, 2018 was less than $1 million.

The fair value of the outstanding derivatives totalled a net liability of $14 million as at March 31, 2018 (December 31, 2017 − $20 million).

Existing pre-tax net losses of $19 million deferred in AOCL as at March 31, 2018 are expected to be reclassified to net income within the next 12 months.

## 12. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices as at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The

methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

Transfers into, out of, or between fair value hierarchy levels are deemed to occur on the date of the event or change in circumstances that causes the transfer to occur.

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other investments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Pooled funds are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices.

Certain investments within the Nuclear Segregated Funds' real assets portfolio are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

The following is a summary of OPG's financial instruments and their fair value as at March 31, 2018 and December 31, 2017:

| | Fair Value | | Carrying Value [1] | | |
|---|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** | **Balance Sheet Line Item** |
| Nuclear Segregated Funds (includes current portion) [2] | **16,909** | 16,724 | **16,909** | 16,724 | Nuclear fixed asset removal and nuclear waste management funds |
| Financing receivables | **1,655** | 1,179 | **1,639** | 1,179 | Financing receivables |
| Investment in Hydro One shares | **170** | 188 | **170** | 188 | Equity securities |
| Payable related to cash flow hedges | **(38)** | (40) | **(38)** | (40) | Long-term accounts payable and accrued charges |
| Long-term debt – OPG (includes current portion) | **(6,539)** | (6,234) | **(6,060)** | (5,735) | Long-term debt |
| Long-term debt – Fair Hydro Trust | **(847)** | (601) | **(836)** | (601) | Long-term debt |
| Other financial instruments | **(5)** | (16) | **(5)** | (16) | Various |

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of the Fair Hydro Trust long-term senior debt including the warehouse credit facility and OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

For the financing receivables related to the Investment Interests acquired from the IESO, fair value is based on projected cash flows and expected returns on the financing receivables. Therefore, the fair value of the financing receivables is based on Level 3 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at March 31, 2018 and December 31, 2017:

| | March 31, 2018 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **6,096** | **4,693** | **-** | **10,789** |
| Investments measured at NAV [1] | | | | **1,378** |
| | | | | **12,167** |
| Due to Province | | | | **(2,508)** |
| Used Fuel Segregated Fund, net | | | | **9,659** |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **4,567** | **3,482** | **-** | **8,049** |
| Investments measured at NAV [1] | | | | **1,132** |
| | | | | **9,181** |
| Due to Province | | | | **(1,931)** |
| Decommissioning Segregated Fund, net | | | | **7,250** |
| Equity securities | **170** | **-** | **-** | **170** |
| Other financial assets | **5** | **-** | **10** | **15** |
| **Liabilities** | | | | |
| Other financial liabilities | **(20)** | **-** | **-** | **(20)** |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

| *(millions of dollars)* | December 31, 2017 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 6,090 | 4,705 | - | 10,795 |
| Investments measured at NAV [1] | | | | 1,292 |
| | | | | 12,087 |
| Due to Province | | | | (2,529) |
| Used Fuel Segregated Fund, net | | | | 9,558 |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 4,547 | 3,487 | - | 8,034 |
| Investments measured at NAV [1] | | | | 1,065 |
| | | | | 9,099 |
| Due to Province | | | | (1,933) |
| Decommissioning Segregated Fund, net | | | | 7,166 |
| Equity securities | 188 | - | - | 188 |
| Other financial assets | 5 | 3 | 6 | 14 |
| **Liabilities** | | | | |
| Other financial liabilities | (28) | (2) | - | (30) |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the period ended March 31, 2018, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, January 1, 2018 | **6** |
| Realized losses included in revenue | **(5)** |
| Purchases | **9** |
| Closing balance, March 31, 2018 | **10** |

**Investments Measured at Net Asset Value**

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at March 31, 2018:

| *(millions of dollars except where noted)* | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice |
|---|---|---|---|---|
| Real Assets | | | | |
| Infrastructure | **1,412** | **805** | **n/a** | **n/a** |
| Real Estate | **994** | **487** | **n/a** | **n/a** |
| Agriculture | **104** | **91** | **n/a** | **n/a** |
| Pooled Funds | | | | |
| Short-term Investments | **33** | **n/a** | **Daily** | **1-5 days** |
| Fixed Income | **461** | **n/a** | **Daily** | **1-5 days** |
| Equity | **972** | **n/a** | **Daily** | **1-5 days** |
| Total | **3,976** | **1,383** | | |

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments in global farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each agriculture fund will be received

based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

## 13. SHARE CAPITAL

Common Shares

As at March 31, 2018 and December 31, 2017, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In March 2018 and December 2017, OPG issued 4,627,343 Class A shares at a price of $43.74 per share and 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $519 million, respectively. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Fair Hydro Trust's acquisitions of Investment Interests from the IESO in March 2018 and December 2017 of $460 million and $1.18 billion, respectively.

As at March 31, 2018, OPG had 16,844,959 Class A shares issued and outstanding at a stated value of $721 million. (December 31, 2017 − 12,217,616 Class A shares issued and outstanding at a stated value of $519 million).

In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisition of Investment Interest from the IESO in April 2018 of $149 million.

## 14. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding as at March 31, 2018 was 269.0 million (year ended December 31, 2017 – 256.7 million). There were no dilutive securities as at March 31, 2018 and December 31, 2017.

## 15. COMMITMENTS AND CONTINGENCIES

### Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

### Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at March 31, 2018, the total amount of guarantees OPG provided to these entities was $83 million (December 31, 2017 − $82 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at March 31, 2018, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

## Contractual Obligations

OPG's contractual obligations as at March 31, 2018 are as follows:

| *(millions of dollars)* | 2018 [1] | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Fuel supply agreements | 141 | 125 | 115 | 88 | 67 | 67 | 603 |
| Contributions to the OPG registered pension plan [2] | 161 | 219 | - | - | - | - | 380 |
| OPG long-term debt repayment | 123 | 368 | 663 | 413 | 172 | 4,321 | 6,060 |
| Interest on OPG long-term debt | 189 | 249 | 227 | 199 | 185 | 3,612 | 4,661 |
| Fair Hydro Trust senior debt repayment | - | 336 | - | - | - | 500 | 836 |
| Interest on Fair Hydro Trust senior debt | 19 | 25 | 17 | 17 | 17 | 177 | 272 |
| Commitments related to Darlington Refurbishment project [3] | 450 | - | - | - | - | - | 450 |
| Commitments related to Ranney Falls GS project | 22 | 4 | - | - | - | - | 26 |
| Operating licences | 30 | 41 | 24 | 28 | 28 | 87 | 238 |
| Operating lease obligations | 21 | 25 | 24 | 22 | 22 | 79 | 193 |
| Unconditional purchase obligations | 41 | 54 | 52 | 4 | - | - | 151 |
| Accounts payable and accrued charges | 859 | 8 | - | - | - | 16 | 883 |
| Other | 69 | 33 | 7 | 1 | 1 | 63 | 174 |
| Total | 2,125 | 1,487 | 1,129 | 772 | 492 | 8,922 | 14,927 |

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

## 16. BUSINESS SEGMENTS

| Segment Income (Loss) for the Three Months Ended March 31, 2018 *(millions of dollars)* | Regulated | | Unregulated | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear Generation | Nuclear Waste Management | Hydro-Electric | Contracted Generation Portfolio | Fair Hydro Trust | Other | Elimination | Total |
| Revenue from contracts with customers | 871 | - | 356 | 149 | - | 10 | - | 1,386 |
| Leasing revenue | 9 | - | - | - | - | 4 | - | 13 |
| Other revenue | - | 33 | - | - | - | 19 | (44) | 8 |
| Total revenue | 880 | 33 | 356 | 149 | - | 33 | (44) | 1,407 |
| Fuel expense | 73 | - | 65 | 17 | - | - | - | 155 |
| Gross margin | 807 | 33 | 291 | 132 | - | 33 | (44) | 1,252 |
| Operations, maintenance and administration | 604 | 33 | 80 | 41 | - | 8 | (44) | 722 |
| Depreciation and amortization | 121 | - | 36 | 20 | - | 9 | - | 186 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 243 | - | 2 | - | 2 | - | 247 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (210) | - | - | - | - | - | (210) |
| Earnings from Fair Hydro Trust | - | - | - | - | (4) | - | - | (4) |
| Income from investments subject to significant influence | - | - | - | (10) | - | - | - | (10) |
| Property taxes | 7 | - | - | 1 | - | 1 | - | 9 |
| Other losses (gains) | - | - | 4 | - | - | (263) | - | (259) |
| Income (loss) before interest and income taxes | 75 | (33) | 171 | 78 | 4 | 276 | - | 571 |
| Net interest expense | | | | | | | | 19 |
| **Income before income taxes** | | | | | | | | 552 |
| Income tax expense | | | | | | | | 13 |
| **Net income** | | | | | | | | 539 |

| Segment (Loss) Income for the Three Months Ended March 31, 2017 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Management | Hydroelectric | Unregulated Contracted Generation Portfolio | Other | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue from contracts with customers | 643 | - | 363 | 143 | 2 | - | 1,151 |
| Leasing revenue | 9 | - | - | - | 14 | - | 23 |
| Other revenue | - | 27 | - | - | 13 | (38) | 2 |
| Total revenue | 652 | 27 | 363 | 143 | 29 | (38) | 1,176 |
| Fuel expense | 68 | - | 73 | 14 | - | - | 155 |
| Gross margin | 584 | 27 | 290 | 129 | 29 | (38) | 1,021 |
| Operations, maintenance and administration | 589 | 29 | 76 | 39 | 13 | (38) | 708 |
| Depreciation and amortization | 107 | - | 34 | 19 | 7 | - | 167 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 234 | - | 2 | 2 | - | 238 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (189) | - | - | - | - | (189) |
| Income from investments subject to significant influence | - | - | - | (10) | - | - | (10) |
| Property taxes | 6 | - | - | 2 | 3 | - | 11 |
| Other gains | - | - | - | - | (3) | - | (3) |
| (Loss) income before interest and income taxes | (118) | (47) | 180 | 77 | 7 | - | 99 |
| Net interest expense | | | | | | | 19 |
| **Income before income taxes** | | | | | | | 80 |
| Income tax expense | | | | | | | 12 |
| **Net income** | | | | | | | 68 |

The earnings from Fair Hydro Trust are comprised of the following for the three months period ended March 31:

| *(millions of dollars)* | 2018 | 2017 |
|---|---|---|
| Revenue | **(1)** | - |
| Operating expenses | **1** | - |
| Interest income | **(10)** | - |
| Interest expense | **6** | - |
| Earnings from Fair Hydro Trust | **(4)** | - |

In December 2017, the Fair Hydro Trust was established as a separate entity to be the financing entity contemplated by the *Ontario Fair Hydro Plan Act, 2017*. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG, and the Trust's financial position and results are consolidated into OPG's financial results. As a legal matter, the assets and liabilities of the Trust do not form part of the assets and liabilities of OPG, and vice versa, pursuant to section 53.1(1.4) of the *Electricity Act, 1998 (Ontario).*

## 17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

| | Three Months Ended March 31 | |
|---|---|---|
| *(millions of dollars)* | **2018** | **2017** |
| Receivables from related parties | **(83)** | 67 |
| Fuel inventory | **10** | 13 |
| Materials and supplies | **12** | 9 |
| Prepaid expenses | **(2)** | (10) |
| Other current assets [1] | **44** | 34 |
| Income taxes payable | **(90)** | (117) |
| Accounts payable and accrued charges | **(45)** | (113) |
| | **(154)** | (117) |

[1] Represents other accounts receivable.

## 18. PAYMENT OF DIVIDEND TO SHAREHOLDER

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

## 19. SALE OF LAKEVIEW SITE

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million, which is net of income tax effects of $68 million, recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund.

**ONTARIO POWER GENERATION INC.,**
**in its capacity as FSM**

# PROCESS CERTIFICATE

*Certificate of the CFO and Treasurer pursuant to section 3.01 of the Change of Law Process Agreement*

**TO:** Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance (the "**Province**")

**RE:** Floating Rate Variable Funding Senior Notes, Series 2017-1 (the "**Series 2017-1 Senior Notes**") in the aggregate maximum principal amount of C$800,000,000, of which $601,290,000 will be drawn on December 21, 2017

**AND RE:** Floating Rate Variable Funding Subordinated Notes, Series 2017-1 (the "**Series 2017-1 Subordinated Notes**") in the maximum principal amount of C$611,764,705.88, of which $459,810,000 will be drawn on December 21, 2017

**AND RE:** Floating Rate Variable Funding Junior Subordinated Notes, Series 2017-1 in the maximum principal amount of C$156,862,745.10, of which $117,900,000 will be drawn on December 21, 2017 (the "**Series 2017-1 Junior Subordinated Notes**" and, together with the Series 2017-1 Senior Notes and the Series 2017-1 Subordinated Notes, the "**Funding Obligations**")

**AND RE:** Fee letter in respect of the Series 2017-1 Senior Notes among Ontario Power Generation Inc., in its capacity as FSM, Royal Bank of Canada, as Administrative Agent, certain CP Conduit Purchasers, the Non-Conduit Purchaser, and certain Group Banks, each as defined therein (the "**Fee Letter**", the terms of which are incorporated by reference in the Reference Documentation relating to the Series 2017-1 Senior Notes)

Reference is made to the Change of Law Process Agreement dated December 21, 2017 among the Province of Ontario and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have the meanings ascribed to such terms in the Change of Law Process Agreement.

Each of the undersigned, being the Chief Financial Officer and Treasurer of OPG acting in its capacity as FSM and holding the offices set forth under their names and signatures below, pursuant to and accordance with clause 3.01 of the Change of Law Process Agreement, hereby certifies for and on behalf of OPG, in its capacity as Financial Services Manager, and not in such officer's personal capacity and intending that this certificate may be relied on by the addressees hereof without independent inquiry, that:

1. I have read and understand the provisions of the Change of Law Process Agreement and all other documents and materials necessary to enable me to deliver this certificate.

2. The material terms of the Series 2017-1 Senior Notes are set forth in Schedule A.

3. The material terms of the Series 2017-1 Subordinated Notes are set forth in Schedule B.

4. The material terms of the Series 2017-1 Junior Subordinated Notes are set forth in Schedule C.

5. The material terms of the Fee Letter are set forth in Schedule D.

6. The Funding Obligations:

   (a) will arise under terms and conditions that are Substantially in the Form of the Reference Documentation applicable thereto;

   (b) in my opinion, are reasonably incurred or effected in compliance with the Act, the General Regulation, any other enactments related thereto and the Financing Plan;

   (c) are of a type and are on terms that a reasonably prudent financial services manager would incur in similar circumstances; and

   (d) reflect, in all material respects, arm's length terms and conditions.

7. No Disclosure Document was used in connection with the offering and sale of the Funding Obligations.

8. Any disclosure made in respect of any of the Funding Obligations (including any Disclosure Document, press release or other written communication prepared for dissemination to third parties in relation to any of the Funding Obligations) that refers to or describes the terms, effect or adherence of or to the Change of Law Process Agreement or the Change of Law Protection Agreement has been made available to the Province prior to use or dissemination, other than where such disclosure was substantially the same as a disclosure previously made.

9. No Breach Event has occurred on or prior to the date hereof, unless such Breach Event has been waived by the Province in writing.

10. At the time the Funding Obligations are incurred, the maximum aggregate payment amounts due or becoming due in the future in respect of Repayments under the Funding Obligations, together with all other outstanding amounts due or becoming due in the future in respect of Repayments under all Approved Obligations, do not exceed the Protection Agreement Maximum applicable on the date hereof.

***[Remainder of page intentionally left blank.]***

**DATED** the 21st day of December, 2017.

Name: Ken Hartwick
Title: Chief Financial Officer and
Senior Vice President

Name: John Lee
Title: Vice President - Treasurer

## SCHEDULE A

| SERIES 2017-1 SENIOR NOTES TERM SHEET | |
|---|---|
| Type of Credit: | Revolving |
| Principal Amount | Aggregate maximum principal amount of C$800,000,000 available under the Series 2017-1 Senior Notes, of which $601,290,000 will be drawn on December 21, 2017 |
| Interest Rate | Variable rate based on ABCP cost of funds or CDOR, as applicable, plus the Applicable Margin (as defined on Schedule D) |
| Interest Payments | Interest is due on the 15th of each month, beginning in January 2018 |
| Discount | N/A |
| Fees | See Schedule D |
| Term to Maturity | Revolving Period ends in December 2019 and Series 2017-1 Senior Notes mature in July, August, September and October 2021 (straight-line repayment of principal over these four months), subject in each case to extensions as described below |
| Amortization | N/A |
| Redemption | N/A |
| Extension | May only be extended with the prior written consent of the Administrative Agent, each Non-Conduit Purchaser and each Funding Agent, and satisfaction of the Rating Agency Condition (each as defined in the Supplemental Indenture creating the Series 2017-1 Senior Notes) |
| Coupon Payments | N/A |

## SCHEDULE B

| SERIES 2017-1 SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Type of Credit: | Revolving |
| Principal Amount | Maximum principal amount of C$611,764,705.88 available under the Series 2017-1 Subordinated Notes, of which $459,810,000 will be drawn on December 21, 2017 |
| Interest Rate | For any payment date, the amount of interest and fees payable to the holders of the Series 2017-1 Senior Notes on such date, expressed as a rate per annum on the weighted average outstanding principal amount of the Series 2017-1 Senior Notes from the preceding payment date to such payment date, plus 0.10% per annum |
| Interest Payments | Interest is due on the 15th of each month, beginning in January 2018 |
| Discount | N/A |
| Fees | N/A |
| Term to Maturity | Revolving Period ends in December 2019 and Series 2017-1 Subordinated Notes mature in July, August, September and October 2021 (straight-line repayment of principal over these four months), subject in each case to extensions as described below |
| Amortization | N/A |
| Redemption | N/A |
| Extension | Automatic extension upon extension of Series 2017-1 Senior Notes |
| Coupon Payments | N/A |

## SCHEDULE C

| SERIES 2017-1 JUNIOR SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Type of Credit: | Revolving |
| Principal Amount | Maximum principal amount of C$156,862,745.10 available under the Series 2017-1 Junior Subordinated Notes, of which $117,900,000 will be drawn on December 21, 2017 |
| Interest Rate | For any payment date, the amount of interest and fees payable to the holders of the Series 2017-1 Senior Notes on such date, expressed as a rate per annum on the weighted average outstanding principal amount of the Series 2017-1 Senior Notes from the preceding payment date to such payment date, plus 0.10% per annum |
| Interest Payments | Interest is due on the 15th of each month, beginning in January 2018 |
| Discount | N/A |
| Fees | N/A |
| Term to Maturity | Revolving Period ends in December 2019 and Series 2017-1 Junior Subordinated Notes mature in July, August, September and October 2021 (straight-line repayment of principal over these four months), subject in each case to extensions as described below |
| Amortization | N/A |
| Redemption | N/A |
| Extension | Automatic extension upon extension of Series 2017-1 Senior Notes |
| Coupon Payments | N/A |

## SCHEDULE D

| FEE LETTER TERMS | |
|---|---|
| Upfront Fee: | An "Upfront Fee" of 20 bps per annum |
| Applicable Margin: | An "Applicable Margin" of 90 basis points (0.90%); provided that (i) for the period commencing on December 21, 2019 and ending on the payment date in May, 2021 (the "**Initial Step-up Period**"), the Applicable Margin shall be equal to 290 basis points (2.90%) (the "**Step-up Applicable Margin**"), and (ii) with respect to each of the six-payment date periods following the Initial Step-up Period (from the day following the payment date in May to the payment date in November or from the day following the payment date in November to the payment date in May, as applicable), the Applicable Margin shall continue to increase by an additional 50 basis points (0.50%) over the Applicable Margin for the Initial Step-up Period or immediately preceding six-payment date period, as applicable, subject to a maximum Applicable Margin of 590 basis points (5.90%) |
| Commitment Fees: | The "Commitment Fee Rate" is based on weighted average monthly utilization and will be payable monthly in arrears on each interest payment date as follows with respect to the preceding interest period based on the rate below and the unutilized amount of the commitment:<br>• A daily rate of 40 bps per annum if utilization on such day is >66.67%<br>• A daily rate of 55 bps per annum if utilization on such day is >33.33% and </= 66.67%<br>• A daily rate of 70 bps per annum if utilization on such day </= 33.33% |
| Other Fees/Expenses: | Reasonable Fees incurred for any professional or other services which include, but are not limited to, reasonable fees of legal counsel, rating agency fees, accountant fees, and any reasonable out-of-pocket expenses (including without limitation, travel, meals etc.), so long as each such reimbursement complies with Ontario Power Generation Inc.'s Standard Form Business Expense Schedule, as amended from time to time. |

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| Budget 2017 / Fiscal Plan ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| Net Income After Tax[1] | 702 | 678 | 726 | - |
| Income Tax PILs | 166 | 135 | 170 | - |
| GRC to OEFC | 214 | 224 | 222 | - |
| Property Tax to OEFC | 18 | 19 | 19 | - |
| **Total OPG** | **1,100** | **1,056** | **1,137** | - |

| OPG 2018-21 Business Plan ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| Net Income After Tax[2] | 995 | 795 | 1,053 | 877 |
| Income Tax PILs | 151 | 54 | 175 | 169 |
| GRC to OEFC | 206 | 209 | 212 | 212 |
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| **Total OPG** | 1,365 | 1,072 | 1,454 | 1,271 |
| | | | | |
| **Variance to 2017 Budget** | 265 | 16 | 317 | - |

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| | | | | |
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**Corporate and Electricity Finance Division**
**February 27, 2018**

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|---|---|---|---|---|
| Net Income ~~After Tax~~[1] | 702 | 678 | 726 | - |
| IFRS Adjustments | (400) | - | (200) | - |
| Net Income (adjusted) | 302 | 678 | 526 | |
| | | | | |
| PILS to OEFC | | | | |
| Income Tax PILs | 166 | 135 | 170 | - |
| GRC to OEFC | 214 | 224 | 222 | - |
| Property Tax to OEFC | 18 | 19 | 19 | - |
| | | | | |
| | | | | |
| Fair Hydro Trust Revenue | 17 | 54 | 99 | |
| | | | | |
| **Total OPG (excluding IFRS adjustments)** | **1,100** | **1,056** | **1,137** | - |

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**Corporate and Electricity Finance Division**
**February 27, 2018**

# ONTARIO POWER GENERATION 2018-2021 BUSINESS PLAN

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## EXECUTIVE SUMMARY

### FISCAL IMPACTS

- The following tables provides a comparison between Budget 2017 and the financial projections submitted by OPG in its 2018-2021 Business Plan including adjustments.
  - Note that OPG contributions to the fiscal plan in Budget 2017 were primarily based on OPG's 2017-19 Business Plan.

| Budget 2017 / Fiscal Plan ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| Net Income After Tax[1] | 702480 | 678 | 726 | -913 |
| Fair Hydro Trust Revenue | 17 | 54 | 99 | 153 |
| IFRS Adjustments | (400) | - | (200) | - |
| Net Income (adjusted) | 97 | 732 | 625 | 1,066 |
| | | | | |
| PILS to OEFC | | | | |
| Income Tax PILs | 92166 | 135135 | 170170 | 298- |
| GRC to OEFC | 205214 | 212224 | 219222 | 220- |
| Property Tax to OEFC | 1818 | 1919 | 1919 | 19- |
| Total PILs | 315 | 366 | 408 | 537 |
| | | | | |
| Total OPG (including IFRS adjustments) | 1,100412 | 11,056,098 | 1,1371,033 | 1,603- |

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| OPG 2018-21 Business Plan / Fiscal Plan 2018 ($M)[1] | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| Net Income | 1,195 | 795 | 1,053 | 1,070 |
| Fair Hydro Trust Revenue | 10 | 80 | 150 | 225 |
| IFRS Adjustments | (300) | (375) | (475) | (425) |
| ONFA Adjustments | 194 | - | - | - |
| **Net Income (adjusted)** | **1,099** | **500** | **728** | **677** |
| | | | | |
| PILS to OEFC | | | | |
| Income Tax PILs | 221 | 54 | 175 | 169 |
| GRC to OEFC | 206 | 209 | 212 | 212 |
| Property Tax to OEFC | 13 | 14 | 14 | 13 |
| **Total PILs** | **440** | **277** | **401** | **394** |
| | | | | |
| **Total OPG (including IFRS adjustments)** | **1,539** | **777** | **1,129** | **1,071** |
| | | | | |
| Variance to Fiscal Plan | **1,127** | **(321)** | **96** | **(532)** |

| ~~OPG 2018-21 Business Plan ($M)~~ | ~~2017-18~~ | ~~2018-19~~ | ~~2019-20~~ | ~~2020-21~~ |
|---|---|---|---|---|
| ~~Net Income After Tax[2]~~ | ~~995~~ | ~~795~~ | ~~1,053~~ | ~~877~~ |
| ~~Income Tax PILs~~ | ~~151~~ | ~~54~~ | ~~175~~ | ~~169~~ |
| ~~GRC to OEFC~~ | ~~206~~ | ~~209~~ | ~~212~~ | ~~212~~ |
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**February 27, 2018**

## ONTARIO POWER GENERATION – BUSINESS PLAN UPDATE

On ~~May~~ November 1~~9~~8, 2016, OPG delivered its 201~~6~~7-1~~9~~8 Business plan to the Minister of Energy.

### Highlights

- OEB was collecting comments on rate-regulated utility pensions and other post-employment benefits (OPEBs) in the electricity and natural gas sectors. OPG is currently collecting pension and OPEB costs from customers on a cash basis, but would prefer to switch to accrual accounting basis. There will be a significant financial impact if OPG needs to permanently collect pension and OPEB costs on cash basis.
- Adoption of IFRS will result in considerably increased income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan.
- OPG's current management compensation restraint initiatives have been a challenge to maintain and attract talents.

### Performance

OPG provided fiscal and calendar year net income expectations.

| *Fiscal* | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| **Net Income Attributable to the Shareholder ($M)** | ~~302~~349 | ~~694~~702 | ~~686~~678 |

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The projected results are in alignment with those from the March 2016 Draft Business planning document. Note the OM&A and CapEx projections deviate from OPG's March and May business plans. The discrepancy is calculated below.

Commented [SQ21]: Need March 2016 BP – could only locate May

**~~May~~ November BP**

| *Calendar* | 2016~~F~~ | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|
| **Net Income Attributable to the Shareholder ($M)** | 438 | 508 | 679 | 729 | 883 | 1,004 |
| **Return on Equity (%)** | 4.2% | 4.8% | 6.0% | 6.1% | 6.9% | 7.3% |
| **Production (net of Surplus Baseload Generation) (TWh)** | 79.2 | 72.5 | 74.0 | 74.2 | 72.0 | 69.8 |
| | | | | | | |
| **OM&A Expenses from Ongoing Operations ($M)** | 2,909 | 2,916 | 2,924 | 2,964 | 2,983 | 2,891 |
| **Δ with ~~March~~ May BP ($M)** | ~~-730~~ | ~~-411~~ | ~~4-10~~ | ~~-126~~ | ~~-167~~ | ~~-169~~ |
| | | | | | | |
| **Capital Expenditures (#M)** | 1,739 | 1,778 | 1,905 | 1,854 | 1,662 | 1,559 |
| **Δ with M~~arch~~ay BP ($M)** | -1 | -13 | -17 | 3 | 0 | 0 |
| | | | | | | |
| **Headcount from Ongoing Operations** | 9,009 | 9,312 | 9,267 | 9,178 | 9,024 | 8,902 |

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## Independent Borrowing Platform

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OPG is in the initial stages of evaluating options to align OPG's capital structure with the more levered deemed capital structure used by the OEB to set OPG's regulated rates.

In doing so, OPG will explore the possibility of establishing an independent borrowing platform in the public markets. In the letter to the Minister of Energy, OPG is of the view that customers will benefit from the improved efficiencies, and lower costs that are driven by greater commercial discipline.

Once the evaluation is completed, options will be presented for shareholder concurrence. In the interim, the Business Plan does not reflect impacts from this proposal.

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**~~July 13~~December 15, 2016**

# OPG 2017-2019 Business Plan

*Ministry of Energy Clarification Questions – OPG Responses Set 2*

**OPG responses have been inserted in blue typeface, after each question. Numbers may not add due to rounding.**

1. What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast?

| OPG 2015-17 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 471 | 586 | 673 |
| Income Taxes | 224 | 159 | 182 |
| **Earnings Before Tax** | **695** | **745** | **855** |

| OPG 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 302 | 694 | 686 |
| Income Taxes | 104 | 245 | 155 |
| **Earnings Before Tax** | **406** | **939** | **841** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | 349 | 702 | 678 | 726 |
| **Income Tax PILs** | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **445** | **868** | **813** | **896** |

**The min drivers of EBT difference between the 2017-2019 BP and the 2016-2018 BP are as follows:**

**2016-17: EBT increase of ~$40M – main drivers include:**

- **Lower OM&A expenses, including the impact of deferring a planned outage at Darlington from Q1 2017 to Q2 2017, and slower than anticipated hiring**
- **Higher nuclear production, including deferral of planned outages**
- **Lower accretion expense, net of regulatory impacts, due to the change in the Nuclear Liabilities related to 2017 ONFA reference plan update**
- **Higher earnings on the Nuclear Segregated Funds due to higher than planned Ontario CPI and better market performance in 2016**
- **Partially offset by the impact of the change in the expected timing of the OEB's decision on new regulated rates from Q1 2017 to the second half of 2017**

**2017-18: EBT decrease of ~$70M – main drivers include:**

- **Finalization of OEB rate application filed in May 2016**
- **Lower nuclear production and higher OM&A expenses resulting from the deferral of the Darlington planned outage from Q1 2017 to Q2 2017**
- **Partially offset by the impact of the change in the expected timing of the OEB's decision on new regulated rates from Q1 2017 to the second half of 2017**

**2018-19: EBT decrease of ~$30M – main drivers include:**

- **Finalization of OEB rate application filed in May 2016**

**The EBT differences between the 2015-2017 BP and the 2016-2018 BP for 2016-17 and 2017-18 relate primarily to changes in assumptions for OPG's rate application, which the 2015-2017 BP contemplated would be effective in 2016 but, in actuality, was filed a year later to be effective in 2017. The 2016-17 EBT difference also reflects lower nuclear production in the 2016-2018 BP.**

2. Can you provide the breakdown of GRC, Proxy Property Tax, and Ontario Capital Tax for fiscal years 2016-2020 based on OPG's 2017-19 business plan?

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **GRC: Payable to OEFC** | | | | |
| **GRC: Payable to NPC** | | | | |
| **Property Tax Payable to OEFC** | 15 | 18 | 19 | 19 |
| **Total** | **336** | **350** | **363** | **362** |
| | | | | |
| **Income Tax [This section is intended to gain insight into the current vs. future taxes, as well as taxes for regulatory purposes.]** | | | | |
| **Current Income Tax Payable** | | | | |
| **Increase/(Decrease) in Future Income Tax Liability** | | | | |
| **Income Taxes Payable to Ratepayers** | | | | |
| **Total** | **96** | **166** | **135** | **170** |

**The table below contains the information requested. *[GRC detail amended from set 1]***

| | Province's March 31 Fiscal Year | | | | |
|---|---|---|---|---|---|
| | Forecast (October 2016) | Forecast (Current) | 2017-2019 BP | | |
| *$ millions* | 2017 | 2017 | 2018 | 2019 | 2020 |
| **Net Income Before Extraordinary Gain Attributable to Shareholder** | **349** | **379** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 209 | 204 | 214 | 224 | 222 |
| GRC: Payable to MOF | 105 | 103 | 111 | 113 | 113 |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 7 | 8 |
| Property Tax Payable to OEFC | 15 | 14 | 18 | 19 | 19 |
| **Total** | **336** | **329** | **350** | **363** | **362** |
| **Income Tax** | | | | | |
| Current Income Tax Payable | 119 | 86 | 109 | 85 | 133 |
| Increase/(Decrease) in Future Income Tax Liability | (39) | 2 | 106 | 123 | 92 |
| Income Taxes Payable to Ratepayers | 15 | 3 | (48) | (73) | (55) |
| **Income Tax PILs** | 96 | 92 | 166 | 135 | 170 |
| **Total Shareholder Return** | **781** | **800** | **1,218** | **1,176** | **1,258** |

3. In addition, could you provide a financial summary of the OPG head office sale (i.e. pre-tax gain of $296)? What is the PIL expense without this headquarter sales gain?

**Below is the financial impact of the gain on the sale of OPG's head office property that is included in the Province's fiscal year ended March 31, 2018:**

Financial Impact of gain on sale of OPG's head office property

| $ millions | **2018*** |
|---|---|
| Earnings Before Tax (EBT) | |
| Assumed Proceeds | 400 |
| Assumed Net Book Value | (104) |
| EBT- Other Income | 296 |
| Income Tax Expense | 74 |
| **Net Income Impact** | **223** |

*Province's fiscal year ended March 31, 2018

**In early January 2017, subsequent to the approval of the 2017-2019 BP, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The transaction is scheduled to close in early April 2017. The pre-tax gross proceeds before closing costs are expected to be $508 M, with a distribution to the Trillium Trust estimated at $285 M.**

- Is there a PILs element related to the headquarter sale in the $166M PIL number provided? [Essentially, we would like OPG's insight on the allocation of $296M to PILs vs. Net Income].

**See table in previous response.**

- Could we also confirm that $296M is the amount built into the 2017-19 BP forecast for 2017-18?

**Confirmed.**

- The 2017-19 BP mentions that a gain on sale of OPG's head office is expected in 2017, "net of new leaseback costs and foregone lease income". Could you please provide how much of the $296 is the leaseback/foregone lease income costs for 2017 and also provide a forecast for the remaining years in the BP (up to 2019).

**The comment that a "gain on sale of OPG's head office is expected in 2017, net of new leaseback costs and foregone lease income" was in the context of overall Net Income changes in 2017 vs 2016. This comment was meant to indicate that the foregone revenue and higher leaseback costs were a year over year reduction in income. The $296M Pre-tax gain does not include this impact. The approximate annual impacts of forgone lease revenue and higher leaseback costs from the sale of OPG's head office property assumed in the 2017-2019 BP are as follows:**

| **Favorarable/(unfavorable)- $ millions** | **2017*** | **2018** | **2019** |
|---|---|---|---|
| Forgone net revenue | (22) | (29) | (29) |
| Leaseback costs | (7) | (9) | (9) |
| Elimination of other costs | 12 | 16 | 16 |
| Forgone Earnings Before Tax (EBT) | (17) | (22) | (22) |

*Sale assumed to occur in April 2017

4. Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "OEB's decision on OPG's rate application is expected during the third quarter of 2017." Is it your current outlook that OEB's decision would still be retroactive to January 1, 2017?

   **Yes – OPG is assuming the new rates will be made effective January 1, 2017.**

5. Could you provide the financing requirements for the Darlington Refurbishment Project separately from other borrowing requirements?

   **OPG does not identify separate financing requirements for the Darlington refurbishment project as the project is part of OPG's overall cash flow needs rather than part of a separate project entity. OPG identifies overall net financing requirements based on operating sources and investment requirements.**

6. Page 1-2 or Appendix 3:
   a) The March 31, 2017 Fiscal Net Income Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.
   b) Page 1 shows the 2016 Forecast of NI Attributable to Shareholder to be $438M. This is Jan 1, 2016 to Dec 31, 2016.
   c) We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?

   **Yes OPG was forecasting ~$34M for Q1 2017 at the time the business plan was prepared.**

   **The current projection for Q1 2017 is ~$66M as submitted in February 2017.**

7. In the past, OPG had a provision of approximately $200 million in their forecast model that was provided. Could you confirm if this provision is included in the current BP numbers? Similarly in the past, could you also provide the forecast model?

8. Can you provide a more detailed financing and liquidity outlook, specifically the operating cash flow section of the cash flow statement, to explain the drivers behind the ~$1B reduction in operating cash flow in 2017, as well as changes throughout 2016-2021? This is in order to reconcile the $1.2B change in net operating cash flow for 2017 from 2016 ($2.739B in 2016 to $1.531B in 2017). The BP states this is due to lower production, a foregone rate rider, and accrual of new rates in net income; however, the movements in the financial statements (i.e., income accounts and B/S operating account movements) are significantly lower than the $1.2B amount.

   **The main drivers of the $1.2B decrease in cash from operations (excluding interest, nuclear funds contributions, Pension contributions, OPEB payments and Internally funded nuclear provision expenditures as shown on page 23 of OPG's 2017-2019 BP document) from 2016 to 2017 are:**
   - **Impact of lower nuclear production in 2017 (~8TWh) due to the start of refurbishment of Unit 2 at Darlington in October 2016**
   - **Impact of lower rate riders, net of the increase in nuclear base rate under OPG's rate smoothing proposal as filed with the OEB in May 2016**
   - **Partly offset by the assumption that a majority of the incremental revenue accrued in 2017 due to higher regulated rates earned from January 2017 to the date of the OEB decision (assumed to be in second half of 2017) would be received in 2018 through an interim period shortfall rider assumed to be authorized by the OEB**
   - **Higher OM&A expenses in 2017**

**The main drivers of the $1.1B increase in cash from operations (excluding interest, nuclear funds contributions, Pension contributions, OPEB payments and Internally funded nuclear provision expenditures as shown on page 23 of OPG's 2017-2019 BP document) from 2017 to 2018 are:**

- **Impact of increase in nuclear base rate under OPG's rate smoothing proposal as filed with the OEB in May 2016**
- **Impact of higher hydroelectric production**
- **Collection of the interim period shortfall rider assumed to be authorized by the OEB**

**The main drivers of the changes in cash from operations (excluding interest, nuclear funds contributions, Pension contributions, OPEB payments and Internally funded nuclear provision expenditures as shown on page 23 of OPG's 2017-2019 BP document) from 2019 to 2021 are:**

- **Impact of higher nuclear base rate under OPG's rate smoothing proposal as filed with the OEB in May 2016 and assumed nuclear rate rider for deferral and variance account balances accumulated to the end of 2018**
- **Partly offset by lower nuclear production due to refurbishment outages**

**Additional Question from Ministry of Finance**

9. Please provide the Darlington Refurbishment headcount to be layered on to headcount graph on page 5 of OPG's 2017-2019 BP document.

**The Darlington Refurbishment headcount for the 2010-2015 period is as follows:**

| | Actual | | | | | |
|---|---|---|---|---|---|---|
| **Headcount** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Darlington Refurbishment | 98 | 180 | 180 | 181 | 189 | 237 |

**The Darlington Refurbishment headcount for the 2016-2021 period can be found on page 21 of OPG's 2017-2019 BP document. For convenience it is included below:**

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| **Headcount** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| Darlington Refurbishment | 458 | 631 | 642 | 626 | 610 | 642 |

# OPG 2017-2019 Business Plan

*Ministry of Energy Clarification Questions – OPG Responses Set 2*

**OPG responses have been inserted in blue typeface, after each question. Numbers may not add due to rounding.**

1. What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast?

| OPG 2015-17 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 471 | 586 | 673 |
| Income Taxes | 224 | 159 | 182 |
| **Earnings Before Tax** | **695** | **745** | **855** |

| OPG 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 302 | 694 | 686 |
| Income Taxes | 104 | 245 | 155 |
| **Earnings Before Tax** | **406** | **939** | **841** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | 349 | 702 | 678 | 726 |
| **Income Tax PILs** | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **445** | **868** | **813** | **896** |

**The min drivers of EBT difference between the 2017-2019 BP and the 2016-2018 BP are as follows:**

**2016-17: EBT increase of ~$40M – main drivers include:**

- **Lower OM&A expenses, including the impact of deferring a planned outage at Darlington from Q1 2017 to Q2 2017, and slower than anticipated hiring**
- **Higher nuclear production, including deferral of planned outages**
- **Lower accretion expense, net of regulatory impacts, due to the change in the Nuclear Liabilities related to 2017 ONFA reference plan update**
- **Higher earnings on the Nuclear Segregated Funds due to higher than planned Ontario CPI and better market performance in 2016**
- **Partially offset by the impact of the change in the expected timing of the OEB's decision on new regulated rates from Q1 2017 to the second half of 2017**

**2017-18: EBT decrease of ~$70M – main drivers include:**

- **Finalization of OEB rate application filed in May 2016**
- **Lower nuclear production and higher OM&A expenses resulting from the deferral of the Darlington planned outage from Q1 2017 to Q2 2017**
- **Partially offset by the impact of the change in the expected timing of the OEB's decision on new regulated rates from Q1 2017 to the second half of 2017**

**2018-19: EBT decrease of ~$30M – main drivers include:**

- **Finalization of OEB rate application filed in May 2016**

**The EBT differences between the 2015-2017 BP and the 2016-2018 BP for 2016-17 and 2017-18 relate primarily to changes in assumptions for OPG's rate application, which the 2015-2017 BP contemplated would be effective in 2016 but, in actuality, was filed a year later to be effective in 2017. The 2016-17 EBT difference also reflects lower nuclear production in the 2016-2018 BP.**

2. Can you provide the breakdown of GRC, Proxy Property Tax, and Ontario Capital Tax for fiscal years 2016-2020 based on OPG's 2017-19 business plan?

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
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| **Income Tax [This section is intended to gain insight into the current vs. future taxes, as well as taxes for regulatory purposes.]** | | | | |
| **Current Income Tax Payable** | | | | |
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**The table below contains the information requested. *[GRC detail amended from set 1]***

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**See table in previous response.**

- Could we also confirm that $296M is the amount built into the 2017-19 BP forecast for 2017-18?

**Confirmed.**

- The 2017-19 BP mentions that a gain on sale of OPG's head office is expected in 2017, "net of new leaseback costs and foregone lease income". Could you please provide how much of the $296 is the leaseback/foregone lease income costs for 2017 and also provide a forecast for the remaining years in the BP (up to 2019).

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   c) We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?

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7. In the past, OPG had a provision of approximately $200 million in their forecast model that was provided. Could you confirm if this provision is included in the current BP numbers? Similarly in the past, could you also provide the forecast model?

8. Can you provide a more detailed financing and liquidity outlook, specifically the operating cash flow section of the cash flow statement, to explain the drivers behind the ~$1B reduction in operating cash flow in 2017, as well as changes throughout 2016-2021? This is in order to reconcile the $1.2B change in net operating cash flow for 2017 from 2016 ($2.739B in 2016 to $1.531B in 2017). The BP states this is due to lower production, a foregone rate rider, and accrual of new rates in net income; however, the movements in the financial statements (i.e., income accounts and B/S operating account movements) are significantly lower than the $1.2B amount.

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   - **Partly offset by the assumption that a majority of the incremental revenue accrued in 2017 due to higher regulated rates earned from January 2017 to the date of the OEB decision (assumed to be in second half of 2017) would be received in 2018 through an interim period shortfall rider assumed to be authorized by the OEB**
   - **Higher OM&A expenses in 2017**

**The main drivers of the $1.1B increase in cash from operations (excluding interest, nuclear funds contributions, Pension contributions, OPEB payments and Internally funded nuclear provision expenditures as shown on page 23 of OPG's 2017-2019 BP document) from 2017 to 2018 are:**

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- **Impact of higher hydroelectric production**
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**The main drivers of the changes in cash from operations (excluding interest, nuclear funds contributions, Pension contributions, OPEB payments and Internally funded nuclear provision expenditures as shown on page 23 of OPG's 2017-2019 BP document) from 2019 to 2021 are:**

- **Impact of higher nuclear base rate under OPG's rate smoothing proposal as filed with the OEB in May 2016 and assumed nuclear rate rider for deferral and variance account balances accumulated to the end of 2018**
- **Partly offset by lower nuclear production due to refurbishment outages**

**Additional Question from Ministry of Finance**

9. Please provide the Darlington Refurbishment headcount to be layered on to headcount graph on page 5 of OPG's 2017-2019 BP document.

**The Darlington Refurbishment headcount for the 2010-2015 period is as follows:**

| | Actual | | | | | |
|---|---|---|---|---|---|---|
| **Headcount** | **2010** | **2011** | **2012** | **2013** | **2014** | **2015** |
| Darlington Refurbishment | 98 | 180 | 180 | 181 | 189 | 237 |

**The Darlington Refurbishment headcount for the 2016-2021 period can be found on page 21 of OPG's 2017-2019 BP document. For convenience it is included below:**

| | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| **Headcount** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| Darlington Refurbishment | 458 | 631 | 642 | 626 | 610 | 642 |

Rating Report

# Ontario Power Generation Inc.

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DBRS

*Insight beyond the rating.*

## Ratings

| Debt | Rating | Rating Action | Trend |
|---|---|---|---|
| Issuer Rating | A (low) | Confirmed | Stable |
| Unsecured Debt | A (low) | Confirmed | Stable |
| Commercial Paper | R-1 (low) | Confirmed | Stable |

## Rating Update

On April 6, 2016, DBRS Limited (DBRS) confirmed the Issuer Rating and Unsecured Debt rating of Ontario Power Generation Inc. (OPG or the Company) at A (low), and the Commercial Paper (CP) rating at R-1 (low), all with Stable trends. The confirmation was largely based on the continuing financial support from the Company's shareholder, the Province of Ontario (the Province; rated AA (low) by DBRS). The Province, through its agent the Ontario Electricity Financial Corporation (OEFC; rated AA (low) by DBRS), provides most of OPG's financing (approximately 63% of total debt). The Company's remaining debt is in the form of non-recourse project finance debt.

The Province announced in January 2016 that OPG will be moving forward with the refurbishment of the Darlington Nuclear Generating Station (the Darlington Refurbishment). The project has a final budget of $12.8 billion, and the refurbishment of the first unit is scheduled to begin in October 2016, with the last unit to be in-service by 2026. DBRS believes that given the complexity and scale of the Darlington Refurbishment, there is significant execution risk as well as the potential for cost overruns. The high capital expenditures (capex) required, albeit spread over a ten-year period, in addition to ongoing maintenance capex (total capex forecast of approximately $2 billion for 2016), are expected to pressure OPG's key credit metrics. Although the Company's cash flow-to-debt and debt-to-capital ratios have remained strong, DBRS expects leverage to increase to approximately 40% during this period of high capex. Additionally, profitability for OPG continues to be challenged as evidenced by the negative EBIT-interest coverage ratio for the year. DBRS notes that while the in-service of the Lower Mattagami River Project (LMRP) and the prescription of 48 previously unregulated hydroelectric facilities to regulated rates in late 2014 have helped improve OPG's EBITDA, the Company's reported corporate return on equity (ROE; 4.1% in 2015) remains far below the approved ROE of 9.3%. This has largely been due to the high cost base of OPG, which has resulted in several disallowances by the Ontario Energy Board (OEB) for the Company to recover forecasted compensation expenses.

OPG plans to submit a five-year application with the OEB later this year for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an incentive regulation (IR) ratemaking methodology, and that prices for nuclear operations be based on a multi-year forecast cost-of-service (COS) approach with IR features. DBRS believes that profitability for OPG could continue to be challenged following a switch to an IR framework, as the introduction of productivity and efficiency targets could further depress earnings. However, through its Business Transformation initiative, OPG has demonstrated its ability to improve efficiency by reducing regular headcount from continuing operations by approximately 2,700 personnel since 2011. Furthermore, earnings should also benefit from the growth in the rate base as Darlington Refurbishment pre-requisite projects are completed, and new regulated rates in 2017.

## Financial Information

| | For the year ended December 31 | | | | |
|---|---|---|---|---|---|
| (CAD millions) | **2015** | **2014** | **2013** | **2012** | **2011** |
| Cash flow/Total debt 1 | 33.2% | 27.0% | 22.9% | 20.8% | 28.9% |
| Total debt in capital structure 1, 2 | 35.9% | 36.9% | 38.9% | 36.9% | 36.8% |
| EBIT gross interest coverage (times) 3 | (0.86) | 0.24 | (1.12) | 0.66 | 0.02 |
| EBITDA gross interest coverage (times) 3 | 2.89 | 2.75 | 2.21 | 3.15 | 2.71 |
| (Cash flow - n.w.f.)/Total debt 4 | 27.5% | 21.3% | 16.5% | 13.8% | 21.1% |

1 Including operating leases. 2 Adjusted for Accumulated Other Comprehensive Income. 3 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds. 4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

## Issuer Description

Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of over 17,000 megawatts (MW) of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

# Rating Considerations

## Strengths

### 1. Support of shareholder (the Province)

The Province indirectly provides OPG with the majority of its long-term funding requirements through the OEFC, a government financing arm for the provincial power companies; however, this debt is not directly guaranteed by the Province. DBRS believes that the Province will continue to support its investment since OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs.

### 2. Dominant market position in Ontario

OPG's importance in Ontario is demonstrated by the fact that it is the primary electricity generator in the Province, accounting for approximately 51% of electricity produced in Ontario in 2015.

### 3. Reasonable regulatory framework

The reasonable regulatory framework has allowed the Company to recover prudently incurred costs. However, DBRS notes that the unsuccessful appeal of the OEB's decision to disallow labour compensation costs related to OPG's nuclear operations has increased uncertainty regarding the Company's ability to fully recover its nuclear cost through future regulated prices (refer to the Regulation section for details).

### 4. Limited nuclear waste management liabilities

As a result of the Ontario Nuclear Funds Agreement (ONFA) with the Province, OPG's exposure relating to nuclear waste management liabilities has been capped at $5.94 billion (in 1999 dollar terms) for the initial 2.23 million used fuel bundles produced. The Company is, however, responsible for the incremental costs related to the management of used fuel bundles in excess of 2.23 million bundles (2.44 million currently). The Province provides a guarantee for any shortfall between the value of the nuclear fund and the Canadian Nuclear Safety Commission consolidated financial guarantee requirement.

## Challenges

### 1. Significant capex program

OPG has a significant capex program underway (approximately $2 billion planned for 2016). The Company also faces significant execution risk associated with the Darlington Refurbishment because of the complexity and scale of the project. It is expected that OPG will not undertake any major capex without having financing and a cost-recovery mechanism in place, thus minimizing the financial risks.

### 2. Nuclear generation risks

Nuclear generation faces higher operating risks than other types of generation because of its complex technology (approximately 57% of OPG's production in 2015). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants as well as the fact that lost revenues resulting from outages are not recoverable through rates.

### 3. High cost base

OPG's high cost base has resulted in several disallowances by the OEB. In its decision on OPG's application for 2014 and 2015 rates, the OEB disallowed recovery of $100 million of compensation costs for each of 2014 and 2015. Additionally, in September 2015, the Supreme Court of Canada upheld the OEB's 2011 decision to disallow $145 million of forecast nuclear compensation costs for 2011 and 2012. DBRS believes that the inability of OPG to fully recover compensation costs in future regulated prices could have a negative impact on earnings and has affected the Company's ability to achieve its approved ROE. DBRS notes that OPG has been combatting this issue through its Business Transformation initiative, which has reduced headcount by over 2,700 since 2011.

### 4. Political intervention

OPG is subject to political intervention, largely because of changes in government mandates and policies as well as limits that restrict revenues and earnings should the price of electricity rise quickly. DBRS notes that the Province has committed to having OPG run more autonomously; however, the risk of further government intervention still exists.

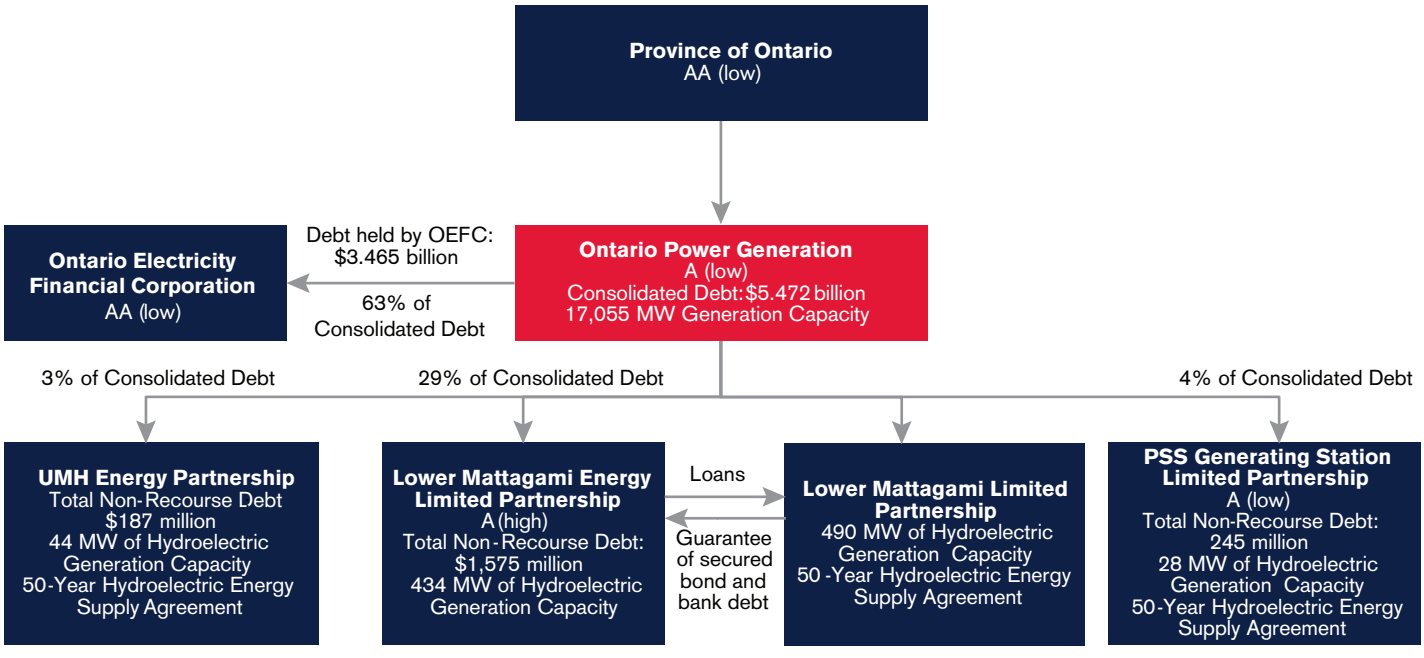
## Major Projects

- **Darlington Refurbishment:** The Darlington Refurbishment will extend the operating life of the Darlington Nuclear Generating Station by approximately 30 years. The execution of the refurbishment for the first unit is scheduled to begin in October 2016, with the last unit scheduled to be completed by 2026.
- **Peter Sutherland Sr. Generating Station Project (PSS GS):** The PSS GS is a 28-MW hydroelectric station on the Abitibi River. The project has a 50-year hydro Energy Supply Agreement (ESA) with the Independent Electricity Systems Operator (IESO; rated A (high) by DBRS), which protects it from hydrology and power price risk. Additionally, OPG guarantees PSS GS's debt until the Recourse Release Date (see DBRS's PSS Generating Station LP (New Post Creek) rating report dated October 23, 2015, for more details).
- **Lower Mattagami River Project (LMRP):** All six units of the LMRP were placed in service as of December 31, 2014. This project, which increased the capacity of four generating stations on the Lower Mattagami River by 438 MW, has a 50-year hydroelectric ESA with the IESO, which provides a utility-like COS revenue requirement for energy produced. In addition, OPG guarantees LMRP's debt until the Recourse Release Date (see DBRS's Lower Mattagami Energy Limited Partnership (LMELP) rating report dated June 4, 2015, for more details).
- **Nanticoke Solar Facility:** OPG announced in March 2016 that it has been selected by the IESO to develop a 44-MW solar facility near the Nanticoke Generating Station. Construction will begin once the Company receives the required approvals and contracts.

| Project | Estimated Cost ($ millions) | Spent as of Dec. 31, 2015 ($ millions) | In-Service Target Date |
|---|---|---|---|
| Darlington Refurbishment | 12,800 | 2,166 | 2026* |
| Peter Sutherland Sr. Generating Station | 300 | 95 | H2 2017 |
| Lower Mattagami River Project | 2,600 | 2,484 | June 2015** |

* Four units with staged in-service. Last unit scheduled to be completed by 2026.
** Entire complex placed in-service by December 2014.

## Simplified Organizational Chart

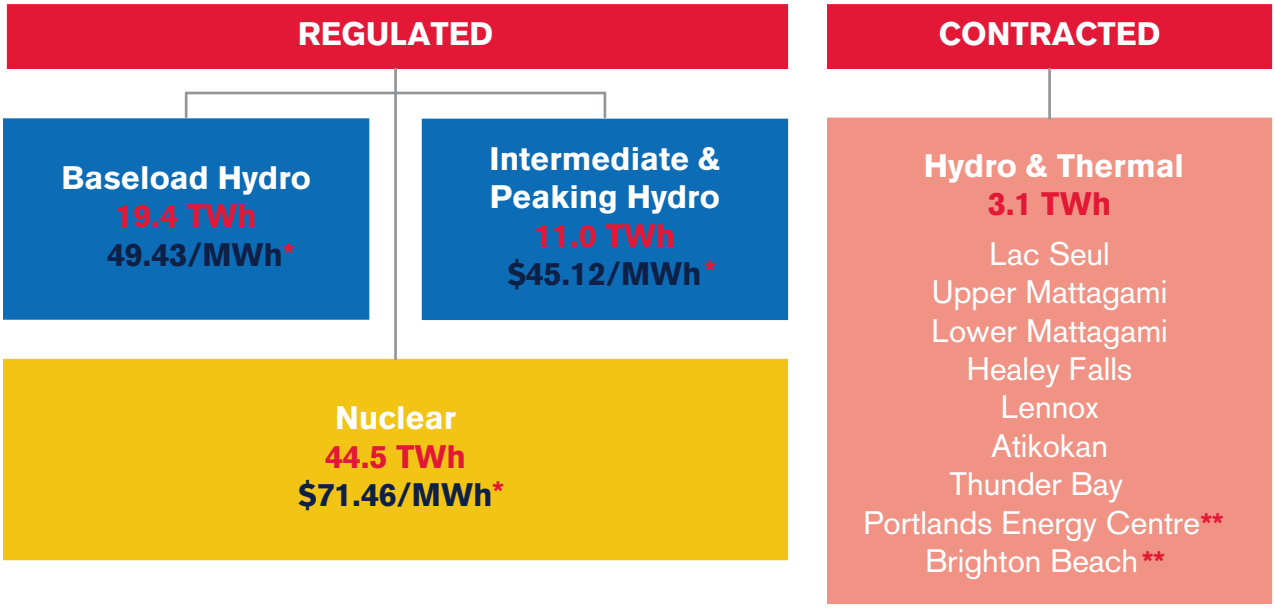



As of December 31, 2015.

## Regulation

- OPG benefits from a reasonable regulated environment. As of December 31, 2015, 96% of its installed in-service capacity is regulated.
- OPG, regulated by the OEB under the *Electricity Restructuring Act, 2004 (Ontario)*, is allowed to receive regulated prices for all electricity generated from its nuclear facilities (6,606 MW) as well as most of its hydroelectric power facilities (6,428 MW).
- An amendment to Ontario Regulation 53/05 (O. Reg. 53/05) by the Ministry of Energy brought all of OPG's previously non-regulated hydroelectric facilities not under an ESA with the IESO to be subject to the OEB's regulation effective July 1, 2014. This amendment provided further stability to the Company's credit profile, as a large majority of installed in-service capacity is now regulated.
- In September 2015, the Supreme Court of Canada overturned the Court of Appeal and upheld the OEB's original decision to disallow a portion of the Company's nuclear compensation costs. DBRS believes that the inability of OPG to fully recover its nuclear compensation in future regulated prices could have a negative impact on earnings.
- The OEB issued its decision on OPG's application for Payment Amounts for Prescribed Facilities for 2014 and 2015 in November 2014, approving the following:
  - A 24-month revenue requirement of approximately $8.1 billion for 2014 and 2015, a reduction of $934 million from the requested amount.
  - Payment amounts effective November 1, 2014, of $40.20/megawatt hour (MWh) for previously regulated hydroelectric facilities, $41.93/MWh for newly regulated hydroelectric facilities and $59.29/MWh for regulated nuclear facilities.
  - Payment riders for the recovery of OEB-authorized regulatory variance and deferral accounts of $6.04/MWh for previously regulated hydroelectric facilities and $1.33/MWh for regulated nuclear facilities, effective January 1, 2015.
  - Deemed capital structure of 55% debt, a change from 53%, with an ROE of 9.36% on regulated base rates for 2014.
- The OEB rejected the previous accrual method of accounting for pension and other post-employment benefit (OPEB) costs for 2014 and 2015 rate setting purposes. OPG will instead include pension and OPEB costs on a cash basis with a deferral account set up to account for the difference. This decreased the Company's revenue requirement by approximately $600 million. A final position on the accrual or cash method will be determined based on a generic proceeding on pension and OPEB costs.
- Other significant outcomes from this decision included (1) a reduction of $100 million of compensation costs in each of 2014 and 2015, (2) disallowance of $88 million related to the Niagara Tunnel Project ($77 million write-off for OPG with $1,365 million approved for inclusion into rate base) and (3) a reduction in the revenue requirement of $70 million from a regulatory tax loss in 2013.
  - OPG subsequently filed an application with the OEB to review and vary the decision in regards to the Niagara Tunnel Project disallowance. The OEB issued a decision in January 2016, reducing the disallowance to $66 million.
- In December 2014, the Company filed an application to recover the balance in its deferral and variance accounts as of December 31, 2014. OPG was seeking to recover approximately $1.3 billion through rate riders over the 18-month period from July 2015 to December 2016, and a further $459 million in a future period.
  - The OEB approved a partial settlement in June 2015 for OPG to recover $669 million from October 1, 2015, to December 31, 2016, and a further $816 million in a future period.
  - Subsequently in September 2015, the OEB approved the Company's recovering the remaining applied-for $263 million.
- OPG plans to file a five-year application with the OEB in 2016 for new regulated rates effective 2017. The OEB has expressed that it expects prices for hydroelectric operations to be based on an IR ratemaking methodology, while prices for nuclear operations be based on a multi-year forecast COS approach with IR features.

## OPG's Price Structure




* Rates as of January 1, 2016.
** 50% ownership interest.

For the year ended December 31, 2015.

- OPG sells electricity to consumers through the IESO.
- Regulated operating divisions sell at rates set by the OEB, which include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- The Contracted Generation Portfolio operating division primarily sells electricity at prices set through ESAs or other long-term contracts with the IESO.

# Earnings and Outlook

| | For the year ended December 31 | | | | |
|---|---|---|---|---|---|
| (CAD millions) | 2015 | 2014 | 2013 | 2012 | 2011 |
| Revenues | 5,476 | 4,963 | 4,863 | 4,732 | 4,964 |
| EBITDA 1 | 848 | 826 | 638 | 841 | 699 |
| EBIT 1 | (252) | 72 | (325) | 177 | 5 |
| Gross interest expense | 293 | 300 | 289 | 267 | 258 |
| Earning before taxes 1 | (407) | 36 | (373) | 86 | (114) |
| Net income before non-recurring items 1 | (271) | 88 | (261) | 115 | 48 |
| Reported net income | 402 | 804 | 135 | 367 | 338 |
| Return on equity | -2.8% | 1.0% | -3.2% | 1.5% | 0.6% |
| | | | | | |
| Hydroelectric rate base | 7,490 | 7,526 | 4,829 | 3,744 | 3,772 |
| Nuclear rate base | 3,659 | 3,707 | 3,780 | 4,133 | 3,859 |
| Approved regulated ROE | 9.30% | 9.36% | 9.55% | 9.55% | 9.43% |
| Achieved regulated ROE | N/A | 6.31% | 0.46% | 4.73% | 4.80% |

1 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

### 2015 Summary

- EBITDA in 2015 increased largely because of (1) higher rates approved by the OEB for the regulated segments, including for the 48 hydroelectric facilities that began receiving regulated rates as of November 1, 2014, (2) the in-service of all units of the LMRP in December 2014 and (3) the conversion to biomass for the Atikokan and Thunder Bay generating stations.
  - The increase was offset by higher operating expenses and lower nuclear generation as a result of the four-unit Darlington Vacuum Building Outage, which reduced generation by 3.6 TWh.
- EBIT decreased significantly because of a $346 million increase in depreciation and amortization. The increase was because of (1) lower depreciation in 2014 caused by higher amounts deferred for that year, (2) higher amortization of regulatory assets and liabilities as OPG began recovering approximately $1.8 billion in its regulatory variance and deferral accounts and (3) higher depreciation following the in-service of the LMRP and the biomass conversion projects.
- Profitability for OPG remains challenged, as the Company achieved a reported corporate ROE of 4.1% for the year, significantly below the approved ROE of 9.30%. DBRS notes that the lower ROE is partly due to the Company's capitalization at around 35% debt versus the regulatory capital structure of 55% debt.

### 2016 Outlook

- EBITDA is expected to remain stable in 2016, as the majority of earnings are expected to continue to be from regulated operations.
- While earnings should benefit from higher rate riders in effect for 2016, net income before non-recurring items is expected to remain weak. Additionally, as the Darlington Refurbishment enters the execution stage, earnings will be negatively affected as each generating unit is temporarily removed from service (first unit in October 2016).
- Earnings volatility going forward will come from (1) adjustments to rate base determined by the OEB and (2) macro factors such as weather, unexpected outages and Ontario's economic conditions.

# Financial Profile

| | For the year ended December 31 | | | | |
|---|---|---|---|---|---|
| (CAD millions) | 2015 | 2014 | 2013 | 2012 | 2011 |
| Net income before non-recurring items 3 | (271) | 88 | (261) | 115 | 48 |
| Depreciation & amortization | 1,100 | 754 | 963 | 664 | 694 |
| Deferred income taxes and other | 1,097 | 730 | 616 | 305 | 693 |
| **Cash flow (bef. working cap. changes)** | **1,926** | **1,572** | **1,318** | **1,084** | **1,435** |
| Nuclear waste funding | (361) | (351) | (383) | (380) | (422) |
| Dividends paid | 0 | 0 | 0 | 0 | 0 |
| Capital expenditures | (1,376) | (1,545) | (1,568) | (1,427) | (1,145) |
| **Free cash flow (bef. working cap. changes)** | **189** | **(324)** | **(633)** | **(723)** | **(132)** |
| Changes in non-cash working cap. items | (100) | 212 | 239 | 172 | 166 |
| **Net free cash flow** | **89** | **(112)** | **(394)** | **(551)** | **34** |
| Long-term investments | (180) | 0 | 0 | 24 | 0 |
| Proceeds on asset sales | 3 | 0 | 0 | 0 | 7 |
| Net equity change | 0 | 0 | 0 | 0 | 0 |
| Net debt change | (33) | 165 | 543 | 310 | 334 |
| Other | (25) | (5) | 0 | 0 | (14) |
| **Change in cash** | **(146)** | **48** | **149** | **(217)** | **361** |
| | | | | | |
| Total debt | 5,697 | 5,730 | 5,657 | 5,114 | 4,804 |
| Cash & equivalents | 464 | 610 | 562 | 413 | 630 |
| Cash flow/Total debt 1 | 33.2% | 27.0% | 22.9% | 20.8% | 28.9% |
| Total debt in capital structure 1, 2 | 35.9% | 36.9% | 38.9% | 36.9% | 36.8% |
| EBIT gross interest coverage (times) 1, 3 | (0.79) | 0.29 | (1.05) | 0.71 | 0.12 |
| (Cash flow - n.w.f.)/Total debt 4 | 27.5% | 21.3% | 16.5% | 13.8% | 21.1% |
| Dividend payout ratio | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |

1 Including operating leases. 2 Adjusted for Accumulated Other Comprehensive Income. 3 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds. 4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

## 2015 Summary

- OPG's debt-to-capital and cash flow-to-debt ratios were strong for the current rating category; however, the Company's EBIT-interest coverage ratio remained weak.
- Cash flow from operations increased because of higher cash receipts from generation following the prescription of the 48 previously non-regulated hydroelectric facilities for regulated rates, and the in-service of the LMRP and biomass conversion projects.
- Capex of $1.4 billion was lower following the completion of the above-mentioned projects. This was offset by construction starting on the PSS GS and continued work for the Darlington Refurbishment project.
- No dividend payments were made to the Province during this period of high capex requirements.
- OPG generated positive free cash flow in 2016, as cash flow from operations were sufficient to cover all expenditures.
- The Company repaid a $500 million note to the OEFC by using cash on hand. PSS GS issued $245 million of bonds, of which $180 million was invested in a structured deposit note with staggered maturity dates. Debt issued by PSS GS, which is guaranteed by the Company, will become non-recourse to OPG once the project is completed and certain requirements are met.

## 2016 Outlook

- OPG has planned capex of $2 billion for 2016, including approximately $1 billion for the Darlington Refurbishment project.
- As the Company continues to execute its large capex program, DBRS expects OPG to generate a free cash flow deficit in 2016. This deficit is expected to be financed with debt and cash on hand. As a result, leverage is expected to increase to nearly 40% over the next few years. DBRS expects the Company to maintain its strong debt-to-capital and cash flow-to-debt ratios in order to offset the weaker EBIT-interest coverage ratio.
- DBRS expects the Province to continue to forego dividends during the Company's large capex program.

# Long-Term Debt Maturities and Credit Facilities

## Long-term Debt

As at December 31, 2015

| (CAD millions) | 2016 | 2017 | 2018 | 2019 | 2020 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Long-term Debt | 273 | 1,103 | 398 | 368 | 663 | 2,667 | 5,472 |
| | 5% | 20% | 7% | 7% | 12% | 49% | 100% |

### Maturity Profile

- The majority of the long-term debt issued at the parent level (approximately $3.465 billion) is held by the OEFC, which is wholly owned by the Ontario government. As a result, DBRS does not expect any material refinancing risk.
- The Company's maturity profile is fairly spread out over the next five years. A modest maturity is expected in 2017 when $900 million of senior notes held by the OEFC come due; however, refinancing risk is expected to be manageable.
- In October 2015, PSS GS issued senior secured bonds totalling $245 million with a maturity date of 2067 and an effective interest rate of 4.90%.

## Credit Facilities as at December 31, 2015 (CAD millions)

| Bank facilities | Maturity | Amount | Outstanding | Available |
|---|---|---|---|---|
| Committed credit facility - Tranche 1 | 20-May-20 | 500 | 0 | 500 |
| Committed credit facility - Tranche 2 | 20-May-20 | 500 | 0 | 500 |
| Short-term uncommitted credit facilities | Demand | 456 | 384 | 72 |
| Short-term uncommitted overdraft facilities | Demand | 25 | 0 | 25 |
| Lower Mattagami River Project - Tranche 1 | 17-Aug-20 | 300 | 225 | 75 |
| Lower Mattagami River Project - Tranche 2 | 17-Aug-16 | 200 | 0 | 200 |
| UMH Energy Partnership credit facilities | 15-Oct-15 | 16 | 14 | 2 |
| UMH Energy Partnership overdraft facilities | 15-Oct-15 | 8 | 0 | 8 |
| **Total** | | **2,005** | **623** | **1,382** |

### Liquidity

- OPG has a reasonable liquidity profile.
- The Company has a $1 billion CP program backed by two tranches of bank facilities (extended due dates of May 20, 2020). All committed bank facilities were unused as at December 31, 2015.
- As at December 31, 2015, OPG had issued $384 million of letters of credit, of which about $345 million was attributed to its supplementary pension plan.
- The Company has separate credit facilities provided by the OEFC for corporate and project financing, which DBRS views as adequate for working capital purposes.

# Company Profile

## Generation Portfolio

As at December 31, 2015

| | | Percent % | Capacity (MW) |
|---|---|---|---|
| **Nuclear** | | | |
| | Darlington | 21% | 3,512 |
| | Pickering A | 6% | 1,030 |
| | Pickering B | 12% | 2,064 |
| | | **39%** | **6,606** |
| **Thermal** | | | |
| | Atikokan (Biomass) | 1% | 205 |
| | Thunder Bay (Biomass) | 1% | 153 |
| | Portlands Energy Centre 1 | 2% | 275 |
| | Brighton Beach 1 | 2% | 280 |
| | Lennox (Dual oil & gas) | 12% | 2,100 |
| | | **18%** | **3,013** |
| **Hydroelectric** | | | |
| **Contracted** 2 | | 6% | 1,006 |
| **Regulated** | | 38% | 6,428 |
| | | **44%** | **7,434** |
| | | | |
| **Other** (Wind) 3 | | 0% | 2 |
| | | | |
| **Total Capacity** | | **100%** | **17,055** |

1 Represents OPG's share of in-service generation. 2 Includes plants under an ESA or a long-term contract with the IESO. 3 One wind-power turbine.

- OPG is the largest generator of electricity in Ontario.
- In 2015, OPG generated 78.0 terawatt hours of electricity with total in-service capacity of 17,055 MW on December 31, 2015.
- OPG partnerships consist of the following:
  - OPG and ATCO Power Canada Ltd. co-own the Brighton Beach Generating Station, a 580-MW natural gas-fired generating station.
  - OPG and TransCanada Energy Ltd. jointly own the Portlands Energy Centre, a 550-MW natural gas-fired generating station.
  - OPG owns the Bruce A and Bruce B nuclear generating stations, which are leased on a long-term basis to Bruce Power Limited Partnership.
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul Generating Station, with LSFN owning 25% of the facility.
  - OPG and the Moose Cree First Nation (MCFN), through its wholly owned subsidiary Amisk-oo-Skow Finance Corporation, jointly own the Little Long, Harmon, Kipling and Smoky Falls generating stations, with MCFN owning 25% of the facilities.

## Ontario Power Generation Inc.

### Balance Sheet

| (CAD millions) | Dec. 31 2015 | 2014 | 2013 |
|---|---|---|---|
| **Assets** | | | |
| Cash & equivalents | 464 | 610 | 562 |
| Accounts receivable | 545 | 482 | 402 |
| Inventories | 440 | 428 | 485 |
| Regulatory assets | 628 | 167 | 306 |
| Prepaid expenses & other | 313 | 161 | 224 |
| **Total Current Assets** | **2,390** | **1,848** | **1,979** |
| Net fixed assets | 20,595 | 17,593 | 16,738 |
| Intangibles | 98 | 76 | 59 |
| Nuclear removal/waste mgmt. funds | 15,121 | 14,354 | 13,471 |
| Regulatory assets | 5,279 | 7,024 | 5,094 |
| Investments, materials & other | 819 | 750 | 750 |
| **Total Assets** | **44,302** | **41,645** | **38,091** |

| | Dec. 31 2015 | 2014 | 2013 |
|---|---|---|---|
| **Liabilities & Equity** | | | |
| S.T. borrowings | 225 | 0 | 32 |
| Accounts payable | 1,228 | 1,151 | 1,026 |
| Current portion L.T.D. | 273 | 503 | 5 |
| Regulatory liabilities | 26 | 5 | 16 |
| Deferred revenue & other | 78 | 36 | 26 |
| **Total Current Liab.** | **1,830** | **1,695** | **1,105** |
| Long-term debt | 5,199 | 5,227 | 5,620 |
| Deferred income taxes | 890 | 828 | 565 |
| Pension & post-retirement benefits | 5,682 | 6,620 | 5,369 |
| Nuclear removal/waste mgmt. funds | 20,169 | 17,028 | 16,257 |
| Regulatory liabilities | 0 | 0 | 0 |
| Payables & other L.T. liab. | 487 | 780 | 841 |
| Shareholders' equity | 10,045 | 9,467 | 8,334 |
| **Total Liab. & SE** | **44,302** | **41,645** | **38,091** |

| | For the year ended December 31 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| **Balance Sheet & Liquidity & Capital Ratios** | | | | | |
| Current ratio | 1.31 | 1.09 | 1.79 | 1.91 | 1.62 |
| Total debt in capital structure | 36.2% | 37.7% | 40.4% | 39.3% | 38.6% |
| Total debt in capital structure 1, 2 | 35.9% | 36.9% | 38.9% | 36.9% | 36.8% |
| Cash flow/Total debt | 33.8% | 27.4% | 23.3% | 21.2% | 29.9% |
| Cash flow/Total debt 1 | 33.2% | 27.0% | 22.9% | 20.8% | 28.9% |
| (Cash flow - dividends)/Capex (times) | 1.40 | 1.02 | 0.84 | 0.76 | 1.25 |
| (Cash flow - n.w.f.)/Total debt 4 | 27.5% | 21.3% | 16.5% | 13.8% | 21.1% |
| Dividend payout ratio | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| **Coverage Ratios (times)** | | | | | |
| EBIT gross interest coverage 3 | (0.86) | 0.24 | (1.12) | 0.66 | 0.02 |
| EBIT gross interest coverage 1, 3 | (0.79) | 0.29 | (1.05) | 0.71 | 0.12 |
| EBITDA gross interest coverage 3 | 2.89 | 2.75 | 2.21 | 3.15 | 2.71 |
| Fixed-charges coverage 3 | (0.86) | 0.24 | (1.12) | 0.66 | 0.02 |
| **Profitability Ratios** | | | | | |
| EBITDA margin 3 | 15.5% | 16.6% | 13.1% | 17.8% | 14.1% |
| EBIT margin 3 | -4.6% | 1.5% | -6.7% | 3.7% | 0.1% |
| Profit margin 3 | -5.0% | 1.8% | -5.4% | 2.4% | 1.0% |
| Return on equity 3 | -2.8% | 1.0% | -3.2% | 1.5% | 0.6% |
| Return on capital 1, 2, 3 | -0.8% | 1.4% | -1.0% | 1.6% | 1.3% |

1 Including operating leases. 2 Adjusted for Accumulated Other Comprehensive Income. 3 Excluding earnings from nuclear fixed asset removal and nuclear waste management funds. 4 Included nuclear waste funding (n.w.f.) payments as they are not discretionary.

## Rating History

| | Current | 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|---|
| Issuer Rating | A (low) | A (low) | A (low) | A (low) | A (low) | NR |
| Unsecured Debt | A (low) | A (low) | A (low) | A (low) | A (low) | A (low) |
| Commercial Paper | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) | R-1 (low) |

## Previous Action

- Confirmed March 24, 2015.

## Commercial Paper Limit

- $1 billion.

## Previous Report

- *Ontario Power Generation*, Rating Report, March 24, 2015.

**Notes:**
All figures are in Canadian dollars unless otherwise noted.

For the definition of Issuer Rating, please refer to Rating Definitions under Rating Policy on **www.dbrs.com**.

Generally, Issuer Ratings apply to all senior unsecured obligations of an applicable issuer, except when an issuer has a significant or unique level of secured debt.

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**ONTARIO ELECTRICITY FINANCIAL CORPORATION**
**BOARD OF DIRECTORS MEETING**
**Trillium Boardroom, 7th Floor, 7 Queen's Park Circle, Toronto**

**JULY 20, 2018 @ 12:30 P.M. – 1:00 P.M.**

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# M I N U T E S

**BOARD MEMBERS PRESENT**
Gadi Mayman, Vice Chair
Denise Dwyer
Nancy Kennedy
Ronald Kwan
John Lieou
Murray Lindo
Maria Mavroyannis
Cindy Veinot

**BOARD MEMBERS ABSENT**
Scott Thompson, Chair
Kaili Sermat-Harding
Sriram Subrahmanyan

## INVITEES PRESENT

**MINISTRY OF FINANCE**
Greg Orencsak - Deputy Minister of Finance

**ONTARIO FINANCING AUTHORITY STAFF**
Ken Kandeepan - Chief Financial and Risk Officer
Sarah Neville - Legal Director
Caroline Swerdlyk - Legal Counsel
Erica Wieder - Manager, Investor Relations, Capital Markets Division

***Documents referred to by Tab number in these minutes were provided to Board members in advance of this meeting, unless otherwise noted.***

## 1. Call to Order

Notice of the meeting having been duly provided to all Board members and a quorum being present, the Vice Chair, Gadi Mayman, called the meeting to order.

## 2. Review of Agenda and Confirmation of Receipt of Meeting Material

The Board reviewed the agenda for the meeting. No changes were made to the agenda. The Board confirmed receipt of the meeting materials for each tab indicated on the agenda.

## 3. Declaration of Possible Conflicts

The Vice Chair asked Board members if they had any conflicts or possible conflicts which had not been declared. No conflicts or possible conflicts were identified.

## 4. Appointment of Sarah Neville as Secretary of the Meeting [Tab 4]

The Vice Chair noted that in the absence of the Corporate Secretary, Mara Collins, it was proposed that Sarah Neville act as Secretary of the meeting.

On motion duly made and seconded, the following resolution was unanimously passed:

RESOLVED that:

> With the consent of the chair of the meeting, Sarah Neville, Legal Director, is appointed to act as Secretary of the meeting.

[Greg Orencsak joined the meeting.]

## 5. Approval of OEFC Financial Statements for the Year Ended March 31, 2018 [Tab 5]

### i. Presentation of financial statements including recommendation of Audit Committee

The Vice Chair referred Board members to OEFC's financial statements for the year ended March 31, 2018 ("Financial Statements") [Tab 5].

The chair of the Audit Committee, Murray Lindo, confirmed that the Audit Committee had met prior to the Board meeting and had reviewed the Financial Statements. Murray Lindo confirmed that Office of the Auditor General ("OAG") staff had presented the Auditor General's Report and had advised the Audit Committee that the Auditor General would issue an unqualified audit opinion on the Financial Statements. Murray Lindo noted that the Audit Committee had requested minor changes to the language in the Auditor General's Report and it would be re-issued.

Murray Lindo noted that the Audit Committee had recommended certain changes to the Financial Statements. Ken Kandeepan indicated that the following change to the Financial Statements was recommended by the Audit Committee:

- **Statement of Operations and Change in Unfunded Liability**: "Payments-in-lieu of tax" was changed to "Payments-in-lieu of tax and provincial corporate taxes". A similar change was also made to the definition of "Payments-in-lieu of taxes in Note 2(e).

Ken Kandeepan distributed to Board members revised pages 6 and 7 of the Financial Statements, containing changes to the Financial Statements that were included in the meeting material. Ken Kandeepan reviewed highlights of the Financial Statements including the changes to pages 6 and 7, and answered questions from the Committee.

### ii. Presentation of Auditor General's Report

Murray Lindo reviewed highlights of the Auditor General's Report, and noted that the Audit Committee had requested minor adjustments to ensure that the descriptions of errors were correct. Murray Lindo and Ken Kandeepan answered questions from the Committee.

### iii. Confirmation of in-camera discussions held by Audit Committee with Chief Financial and Risk Officer; Director, Internal Audit; and Director, Office of the Auditor General

Murray Lindo confirmed that the Audit Committee held in-camera discussions with each of the Chief Financial and Risk Officer, Internal Audit Division staff, and Office of the Auditor General staff, and that no issues were identified which would negatively impact a decision to approve the financial statements.

Murray Lindo indicated that Internal Audit Division staff had noted pressures on staffing and they would be providing an update on audit plan priorities at or prior to the next Audit Committee meeting.

### iv. Opportunity for further in-camera discussion if required

The Board confirmed that no further in-camera discussions were required.

### v. Approval of financial statements by the Board

On motion duly made and seconded, the following resolution was unanimously passed:

RESOLVED that:

1. The financial statements of the OEFC for the year ended March 31, 2018, in the form presented to this meeting, as amended at this meeting, are approved.

2. Mechanical reproduction of the signatures of the Chair and CEO through electronic scanning or otherwise on the financial statements is authorized and approved.

### vi. Execution of financial statements

Sarah Neville indicated that the Financial Statements would be signed by the Chair of OEFC.

### vii. Status of Auditor General's audit opinion

Ken Kandeepan confirmed that the Office of the Auditor General had indicated that it would be issuing an unqualified audit opinion on the Financial Statements.

## 6. Approval of OEFC 2018 Annual Report [Tab 6]

Erica Wieder referred Board members to the OEFC 2018 Annual Report (the "Annual Report") [Tab 6]. Erica Wieder provided highlights of the Annual Report noting the changes from the prior year's report. She indicated that references to the Chair on pages 30 and 32 of the Annual Report would be reviewed and amended if required, based on the individual that was the Chair as of the end of the day.

On motion duly made and seconded, the following resolution was unanimously passed:

RESOLVED that:

1. The Ontario Electricity Financial Corporation 2018 Annual Report, substantially in the form of the draft presented to this meeting, is approved for submission to the Minister of Finance, subject to the inclusion in the Annual Report of the Auditor General's audit opinion.

2. Each of the Chair and the CEO is authorized to approve any non-material changes to the 2018 Annual Report and the Chair is authorized and directed to submit the 2018 Annual Report to the Minister of Finance.

3. The mechanical reproduction of signatures of the Chair and CEO, through electronic scanning or otherwise, in the 2018 Annual Report is authorized and approved.

## 7. Approval of Revised Policy on the Use of Derivatives [Tab 7]

The Vice Chair referred Board members to the briefing note "Revisions to the OEFC Policy on the Use of Derivatives and Other Financial Instruments" dated July 20, 2018 and the draft "Policy on the Use of Derivatives and Other Financial Instruments - OEFC Treasury Program" ("Policy") [Tab 7]. Sarah Neville noted that the Audit Committee had reviewed the draft Policy and recommended the following amendment:

- In the third bullet of s. 8.6 (Finance and Treasury Division (FTD)), the second sentence was deleted and replaced with the following: "Consults with the Office of the Provincial Controller and where agreed, external subject matter experts".

Ken Kandeepan reviewed the proposed revisions contained in the Policy and noted that similar changes had been approved by the OFA Board.

On motion duly made and seconded, the following resolution was unanimously passed:

RESOLVED that:

> The revised Policy on the Use of Derivatives and Other Financial Instruments – OEFC Treasury Program, in the form presented to this meeting, as amended at this meeting, is approved.

## 8. Approval of Minutes of Board Meeting Held on June 22, 2018 [Tab 8]

The Vice Chair referred Board members to the minutes of the Board meeting held on June 22, 2018 [Tab 8].

On motion duly made and seconded, the following resolution was unanimously passed:

RESOLVED that:

> The OEFC Board of Directors minutes of the meeting held on June 22, 2018, in the form presented to this meeting, are approved.

## 9. Other Business

Ronald Kwan provided an update to the Board on the status of the power purchase agreement with the Power Limited Partnership.

## 10. Termination

It was resolved that:

This meeting is terminated.

_____
Vice Chair

_____
Secretary of the meeting

*Summary:*

| **Total Funding** | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

| Date Issued | Debt Type | Amount | Interest Rate |
|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000.00 | 3.357% |
| February 9, 2018 | Subordinated | 382,353,000.00 | 3.637% |
| February 9, 2018 | Junior subordinated | 98,040,000.00 | 3.957% |
| April 24, 2018 | Senior debt | 400,000,000.00 | 3.520% |
| April 24, 2018 | Subordinated | 305,882,000.00 | 3.834% |
| April 24, 2018 | Junior subordinated | 78,431,000.00 | 4.214% |
| | | | |
| | | | |
| | | | |
| | | | |

| Maturity Date | Series Number | Comments |
|---|---|---|
| May 15, 2033 | 2018-1 | |
| May 15, 2033 | 2018-1 | |
| May 15, 2033 | 2018-1 | |
| May 15, 2038 | 2018-2 | |
| May 15, 2038 | 2018-2 | |
| May 15, 2038 | 2018-2 | |
| | | |
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| | | |
| | | |

| | Weighted Average | Ont Interest Rate - 30yr |
|---|---|---|
| Feb | 3.526% | 3.23% |
| Apr | 3.712% | 3.23% |
| **Total** | **3.609%** | |

| Source |
| --- |
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(Feb 12 rate)
(Apr 24 rate)

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**April 19, 2018 Debt Financing**

| **IESO Asset Purchase:** |
|---|
| 460,000,000.00 |
| 149,000,000.00 |
| **609,000,000.00** |
| **Remaining Balance from Previous:** |
| **198,607,000.00** |
| **Starting Balance:** |
| **807,607,000.00** |

| **Warehouse Funding** | | | **Starting Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 411,879,570.00 |
| Subordinated | 39/51 X B | | 314,966,730.00 |
| Junior subordinated | 10/51 X B | | 80,760,700.00 |
| | | | 807,607,000.00 |
| | | | |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| | | | |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 411,879,570.00 |
| Subordinated | | 39.00% | 314,966,730.00 |
| Junior subordinated | | 10.00% | 80,760,700.00 |
| | | | 807,607,000.00 |

| **Term debt takeout** | | |
|---|---|---|
| **(980,392,156.86)** | **Ending Balance** | |
| (400,000,000.00) | 11,879,570.00 | 51% |
| (305,882,000.00) | 9,084,730.00 | 39% |
| (78,431,000.00) | 2,329,700.00 | 10% |
| (784,313,000.00) | 23,294,000.00 | |
| | | |
| 400,000,000.00 | 400,000,000.00 | 51% |
| 305,882,000.00 | 305,882,000.00 | 39% |
| 78,431,000.00 | 78,431,000.00 | 10% |
| 784,313,000.00 | 784,313,000.00 | |
| | | |
| - | 411,879,570.00 | 51% |
| - | 314,966,730.00 | 39% |
| - | 80,760,700.00 | 10% |
| 0.00 | 807,607,000.00 | |

**February 6, 2018 Debt Financing**

| Initial Balance: |
|---|
| 1,179,000,000.00 |

| **Warehouse Funding** | | | **Initial Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 601,290,000.00 |
| Subordinated | 39/51 X B | | 459,810,000.00 |
| Junior subordinated | 10/51 X B | | 117,900,000.00 |
| | | | 1,179,000,000.00 |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 601,290,000.00 |
| Subordinated | | 39.00% | 459,810,000.00 |
| Junior subordinated | | 10.00% | 117,900,000.00 |
| | | | 1,179,000,000.00 |

| Term debt takeout (980,392,156.86) | Ending Balance | |
|---|---|---|
| (500,000,000.00) | 101,290,000.00 | 51% |
| (382,353,000.00) | 77,457,000.00 | 39% |
| (98,040,000.00) | 19,860,000.00 | 10% |
| (980,393,000.00) | 198,607,000.00 | |
| | | |
| 500,000,000.00 | 500,000,000.00 | 51% |
| 382,353,000.00 | 382,353,000.00 | 39% |
| 98,040,000.00 | 98,040,000.00 | 10% |
| 980,393,000.00 | 980,393,000.00 | |
| | | |
| - | 601,290,000.00 | 51% |
| - | 459,810,000.00 | 39% |
| - | 117,900,000.00 | 10% |
| 0.00 | 1,179,000,000.00 | |

*Summary:*

| **Total Funding** | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

| Date Issued | Debt Type | Amount | Interest Rate |
|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000.00 | 3.357% |
| February 9, 2018 | Subordinated | 382,353,000.00 | 3.637% |
| February 9, 2018 | Junior subordinated | 98,040,000.00 | 3.957% |
| April 24, 2018 | Senior debt | 400,000,000.00 | 3.520% |
| April 24, 2018 | Subordinated | 305,882,000.00 | 3.834% |
| April 24, 2018 | Junior subordinated | 78,431,000.00 | 4.214% |
| | | | |
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| | | | |

| Issuing Month | Weighted Average | Ont Interest Rate - 30yr | Notes |
|---|---|---|---|
| February 9, 2018 | 3.526% | 3.23% | (Feb 12 rate) |
| April 24, 2018 | 3.712% | 3.23% | (Apr 24 rate) |
| **Total** | **3.609%** | | |

| Maturity Date | Series Number | Comments | Source |
|---|---|---|---|
| May 15, 2033 | 2018-1 | | Link |
| May 15, 2033 | 2018-1 | | Link |
| May 15, 2033 | 2018-1 | | Link |
| May 15, 2038 | 2018-2 | | LInk |
| May 15, 2038 | 2018-2 | | LInk |
| May 15, 2038 | 2018-2 | | LInk |
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| | | | |
| | | | |

**April 19, 2018 Debt Financing**

| **IESO Asset Purchase:** |
|---|
| 460,000,000.00 |
| 149,000,000.00 |
| **609,000,000.00** |
| **Remaining Balance from Previous:** |
| **198,607,000.00** |
| **Starting Balance:** |
| **807,607,000.00** |

| **Warehouse Funding** | | | **Starting Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 411,879,570.00 |
| Subordinated | 39/51 X B | | 314,966,730.00 |
| Junior subordinated | 10/51 X B | | 80,760,700.00 |
| | | | 807,607,000.00 |
| | | | |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| | | | |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 411,879,570.00 |
| Subordinated | | 39.00% | 314,966,730.00 |
| Junior subordinated | | 10.00% | 80,760,700.00 |
| | | | 807,607,000.00 |

| **Term debt takeout** | | |
|---|---|---|
| **(980,392,156.86)** | **Ending Balance** | |
| (400,000,000.00) | 11,879,570.00 | 51% |
| (305,882,000.00) | 9,084,730.00 | 39% |
| (78,431,000.00) | 2,329,700.00 | 10% |
| (784,313,000.00) | 23,294,000.00 | |
| | | |
| 400,000,000.00 | 400,000,000.00 | 51% |
| 305,882,000.00 | 305,882,000.00 | 39% |
| 78,431,000.00 | 78,431,000.00 | 10% |
| 784,313,000.00 | 784,313,000.00 | |
| | | |
| - | 411,879,570.00 | 51% |
| - | 314,966,730.00 | 39% |
| - | 80,760,700.00 | 10% |
| 0.00 | 807,607,000.00 | |

**February 6, 2018 Debt Financing**

| Initial Balance: |
|---|
| 1,179,000,000.00 |

| **Warehouse Funding** | | | **Initial Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 601,290,000.00 |
| Subordinated | 39/51 X B | | 459,810,000.00 |
| Junior subordinated | 10/51 X B | | 117,900,000.00 |
| | | | 1,179,000,000.00 |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 601,290,000.00 |
| Subordinated | | 39.00% | 459,810,000.00 |
| Junior subordinated | | 10.00% | 117,900,000.00 |
| | | | 1,179,000,000.00 |

| Term debt takeout (980,392,156.86) | Ending Balance | |
|---|---|---|
| (500,000,000.00) | 101,290,000.00 | 51% |
| (382,353,000.00) | 77,457,000.00 | 39% |
| (98,040,000.00) | 19,860,000.00 | 10% |
| (980,393,000.00) | 198,607,000.00 | |
| | | |
| 500,000,000.00 | 500,000,000.00 | 51% |
| 382,353,000.00 | 382,353,000.00 | 39% |
| 98,040,000.00 | 98,040,000.00 | 10% |
| 980,393,000.00 | 980,393,000.00 | |
| | | |
| - | 601,290,000.00 | 51% |
| - | 459,810,000.00 | 39% |
| - | 117,900,000.00 | 10% |
| 0.00 | 1,179,000,000.00 | |

*Summary:*

| Total Funding | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

| Issuing Month | Weighted Average | Ont Yield - 30yr | Ont Yield - 30yr w/ Commission | Debt Issue Maturity | Ont Rate | Ont Rate - w/ Commission | Notes | Souce |
|---|---|---|---|---|---|---|---|---|
| February 9, 2018 | 3.526% | 3.23% | 3.25% | 15 year | 3.10% | 3.14% | (Feb 9 Rate) | Link |
| April 24, 2018 | 3.712% | 3.23% | 3.26% | 20 year | 3.22% | 3.25% | (Apr 24 rate) | Link |
| **Total** | **3.609%** | | | | | | | |

| Date Issued | Debt Type | Amount | Interest Rate | Maturity Date | Series Number | Comments | Source |
|---|---|---|---|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000.00 | 3.357% | May 15, 2033 | 2018-1 | | Link |
| February 9, 2018 | Subordinated | 382,353,000.00 | 3.637% | May 15, 2033 | 2018-1 | | Link |
| February 9, 2018 | Junior subordinated | 98,040,000.00 | 3.957% | May 15, 2033 | 2018-1 | | Link |
| April 24, 2018 | Senior debt | 400,000,000.00 | 3.520% | May 15, 2038 | 2018-2 | | LInk |
| April 24, 2018 | Subordinated | 305,882,000.00 | 3.834% | May 15, 2038 | 2018-2 | | LInk |
| April 24, 2018 | Junior subordinated | 78,431,000.00 | 4.214% | May 15, 2038 | 2018-2 | | LInk |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |
| | | | | | | | |

*Summary:*

| Total Funding | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

**Fair Hydro Trust**

| Date Issued | Fair Hydro Trust Debt Type | Amount | Interest Rate | Maturity Date | Series Number | Comments | Source |
|---|---|---|---|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000.00 | 3.357% | May 15, 2033 | 2018-1 | | Link |
| February 9, 2018 | Subordinated | 382,353,000.00 | 3.637% | May 15, 2033 | 2018-1 | | Link |
| February 9, 2018 | Junior subordinated | 98,040,000.00 | 3.957% | May 15, 2033 | 2018-1 | | Link |
| April 24, 2018 | Senior debt | 400,000,000.00 | 3.520% | May 15, 2038 | 2018-2 | | LInk |
| April 24, 2018 | Subordinated | 305,882,000.00 | 3.834% | May 15, 2038 | 2018-2 | | LInk |
| April 24, 2018 | Junior subordinated | 78,431,000.00 | 4.214% | May 15, 2038 | 2018-2 | | LInk |

| Issuing Month | Weighted Average |
|---|---|
| February 9, 2018 | 3.526% |
| April 24, 2018 | 3.712% |
| **Total** | **3.609%** |

**Ontario Bond Yields**

| 30yr | 30yr w/ Commission | Debt Issue Maturity | Ont Rate | Ont Rate - w/ Commission | Notes | Souce |
|---|---|---|---|---|---|---|
| 3.23% | 3.25% | 15 year | 3.10% | 3.14% | (Feb 9 Rate) | Link |
| 3.23% | 3.26% | 20 year | 3.22% | 3.25% | (Apr 24 rate) | Link |

*Summary:*

| Total Funding | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

*Comparison to Ont*

| Issuing Month |
|---|
| February 9, 2018 |
| April 24, 2018 |
| **Total** |

| Date Issued | Debt Type | Amount | Interest Rate | Maturity Date |
|---|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000.00 | 3.357% | May 15, 2033 |
| February 9, 2018 | Subordinated | 382,353,000.00 | 3.637% | May 15, 2033 |
| February 9, 2018 | Junior subordinated | 98,040,000.00 | 3.957% | May 15, 2033 |
| April 24, 2018 | Senior debt | 400,000,000.00 | 3.520% | May 15, 2038 |
| April 24, 2018 | Subordinated | 305,882,000.00 | 3.834% | May 15, 2038 |
| April 24, 2018 | Junior subordinated | 78,431,000.00 | 4.214% | May 15, 2038 |
| | | | | |
| | | | | |
| | | | | |
| | | | | |

*ario Rates:*

| Weighted Average | Ont Yield - 30yr | Ont Yield - 30yr w/ Commission | Debt Issue Maturity | Ont Rate |
|---|---|---|---|---|
| 3.526% | 3.23% | 3.25% | 15 year | 3.10% |
| 3.712% | 3.23% | 3.26% | 20 year | 3.22% |
| **3.609%** | | | | |

| Series Number | Comments | Source |
|---|---|---|
| 2018-1 | | Link |
| 2018-1 | | Link |
| 2018-1 | | Link |
| 2018-2 | | Link |
| 2018-2 | | Link |
| 2018-2 | | Link |
| | | |
| | | |
| | | |
| | | |

| Ont Rate - w/ Commission | Notes | Souce |
|---|---|---|
| 3.14% | Feb 9 Rate - Si | Link |
| 3.25% | Apr 24 Rate | Link |
| | | |

**April 19, 2018 Debt Financing**

| **IESO Asset Purchase:** |
|---|
| 460,000,000.00 |
| 149,000,000.00 |
| **609,000,000.00** |
| **Remaining Balance from Previous:** |
| **198,607,000.00** |
| **Starting Balance:** |
| **807,607,000.00** |

| **Warehouse Funding** | | | **Starting Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 411,879,570.00 |
| Subordinated | 39/51 X B | | 314,966,730.00 |
| Junior subordinated | 10/51 X B | | 80,760,700.00 |
| | | | 807,607,000.00 |
| | | | |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| | | | |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 411,879,570.00 |
| Subordinated | | 39.00% | 314,966,730.00 |
| Junior subordinated | | 10.00% | 80,760,700.00 |
| | | | 807,607,000.00 |

| **Term debt takeout** | | |
|---|---|---|
| **(980,392,156.86)** | **Ending Balance** | |
| (400,000,000.00) | 11,879,570.00 | 51% |
| (305,882,000.00) | 9,084,730.00 | 39% |
| (78,431,000.00) | 2,329,700.00 | 10% |
| (784,313,000.00) | 23,294,000.00 | |
| | | |
| 400,000,000.00 | 400,000,000.00 | 51% |
| 305,882,000.00 | 305,882,000.00 | 39% |
| 78,431,000.00 | 78,431,000.00 | 10% |
| 784,313,000.00 | 784,313,000.00 | |
| | | |
| - | 411,879,570.00 | 51% |
| - | 314,966,730.00 | 39% |
| - | 80,760,700.00 | 10% |
| 0.00 | 807,607,000.00 | |

**February 6, 2018 Debt Financing**

| Initial Balance: |
|---|
| 1,179,000,000.00 |

| **Warehouse Funding** | | | **Initial Balance** |
|---|---|---|---|
| Senior debt | B=51% x A | | 601,290,000.00 |
| Subordinated | 39/51 X B | | 459,810,000.00 |
| Junior subordinated | 10/51 X B | | 117,900,000.00 |
| | | | 1,179,000,000.00 |
| **Term Debt Funding** | | | |
| Senior debt | | 51.00% | |
| Subordinated | | 39.00% | |
| Junior subordinated | | 10.00% | |
| | | | - |
| **Total Funding** | | | |
| Senior debt | | 51.00% | 601,290,000.00 |
| Subordinated | | 39.00% | 459,810,000.00 |
| Junior subordinated | | 10.00% | 117,900,000.00 |
| | | | 1,179,000,000.00 |

| Term debt takeout (980,392,156.86) | Ending Balance | |
|---|---|---|
| (500,000,000.00) | 101,290,000.00 | 51% |
| (382,353,000.00) | 77,457,000.00 | 39% |
| (98,040,000.00) | 19,860,000.00 | 10% |
| (980,393,000.00) | 198,607,000.00 | |
| | | |
| 500,000,000.00 | 500,000,000.00 | 51% |
| 382,353,000.00 | 382,353,000.00 | 39% |
| 98,040,000.00 | 98,040,000.00 | 10% |
| 980,393,000.00 | 980,393,000.00 | |
| | | |
| - | 601,290,000.00 | 51% |
| - | 459,810,000.00 | 39% |
| - | 117,900,000.00 | 10% |
| 0.00 | 1,179,000,000.00 | |

*Summary:*

| Total Funding | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

**Fair Hydro Trust**

| Date Issued* | Fair Hydro Trust Debt Type* | Principal Amount* ($) | Coupon Rate* | Maturity Date* | Series Number* | Term to Maturity [Years] | Issue Price [per $100 Principal]* | Issue Discount/(Premium) [per $100 Principal] | Commission [per $100 Principal]* | Commission and Issue Discount/(Premium) [Per $100 Principal] | Commission and Issue Premium/Discount [interest rate per annum] | Yield at Issue (w/ Commission, w/ Discount/Premium) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000 | 3.357% | May 15, 2033 | 2018-1 | 15.27 | 100.003 | (0.003) | 0.500 | 0.497 | 0.042% | 3.42705% |
| February 9, 2018 | Subordinated | 382,353,000 | 3.637% | May 15, 2033 | 2018-1 | 15.27 | 100.000 | - | - | - | 0.000% | 3.67007% |
| February 9, 2018 | Junior subordinated | 98,040,000 | 3.957% | May 15, 2033 | 2018-1 | 15.27 | 100.000 | - | - | - | 0.000% | 3.99614% |
| April 24, 2018 | Senior debt | 400,000,000 | 3.520% | May 15, 2038 | 2018-2 | 20.06 | 100.002 | (0.002) | 0.550 | 0.548 | 0.038% | 3.58930% |
| April 24, 2018 | Subordinated | 305,882,000 | 3.834% | May 15, 2038 | 2018-2 | 20.06 | 100.000 | - | - | - | 0.000% | 3.87075% |
| April 24, 2018 | Junior subordinated | 78,431,000 | 4.214% | May 15, 2038 | 2018-2 | 20.06 | 100.000 | - | - | - | 0.000% | 4.25839% |

| Issuing Date | Weighted Average Coupon Rate | Weighted Average Yield at Issue |
|---|---|---|
| February 9, 2018 | 3.526% | 3.579% |
| April 24, 2018 | 3.712% | 3.766% |
| **Total** | **3.609%** | **3.662%** |

**Ontario Bond Yields**

| 30 yr yields | | Yields reflective of Debt's Maturity | | | |
|---|---|---|---|---|---|
| 30yr** | 30yr w/ Commission** | Debt Issue Maturity** | Ont Rate** | Ont Rate - w/ Commission** | Notes |
| 3.23% | 3.25% | 15 year | 3.10% | 3.14% | Feb 9 Rate, Simple average between 10 and 20 year rates. |
| 3.23% | 3.26% | 20 year | 3.22% | 3.25% | Apr 24 Rate |

**Source: Fair Hydro Plan - Deliveries under Change of Law Process Agreement, February 8, 2018 and April 23, 2018.*

***Source: Corporate Finance Branch Interest Rate Snapshot based on ScotiaBank daily reports, estimates. Commissions are for dealers, based on historical one-time estimate. Subject to revision. Excludes additional costs Province may charge for on lending purposes.*

*Summary:*

| Total Funding | Term Debt Takeout |
|---|---|
| Senior debt | 900,000,000.00 |
| Subordinated | 688,235,000.00 |
| Junior subordinated | 176,471,000.00 |
| **Total** | **1,764,706,000.00** |

**Fair Hydro Trust**

| Date Issued* | Fair Hydro Trust Debt Type* | Principal Amount* ($) | Coupon Rate* | Maturity Date* | Series Number* | Term to Maturity [Years] | Issue Price [per $100 Principal]* | Issue Discount/(Premium) [per $100 Principal] | Commission [per $100 Principal]* | Commission and Issue Discount/(Premium) [Per $100 Principal] | Commission and Issue Premium/Discount [semi-annual rate] | Yield at Issue (w/ Commission, w/ Discount/Premium) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| February 9, 2018 | Senior debt | 500,000,000 | 3.357% | May 15, 2033 | 2018-1 | 15.27 | 100.003 | (0.003) | 0.500 | 0.497 | 0.042% | 3.39887% |
| February 9, 2018 | Subordinated | 382,353,000 | 3.637% | May 15, 2033 | 2018-1 | 15.27 | 100.000 | - | - | - | 0.000% | 3.63700% |
| February 9, 2018 | Junior subordinated | 98,040,000 | 3.957% | May 15, 2033 | 2018-1 | 15.27 | 100.000 | - | - | - | 0.000% | 3.95700% |
| April 24, 2018 | Senior debt | 400,000,000 | 3.520% | May 15, 2038 | 2018-2 | 20.06 | 100.002 | (0.002) | 0.550 | 0.548 | 0.038% | 3.55832% |
| April 24, 2018 | Subordinated | 305,882,000 | 3.834% | May 15, 2038 | 2018-2 | 20.06 | 100.000 | - | - | - | 0.000% | 3.83400% |
| April 24, 2018 | Junior subordinated | 78,431,000 | 4.214% | May 15, 2038 | 2018-2 | 20.06 | 100.000 | - | - | - | 0.000% | 4.21400% |

**Ontario Bond Yields**

| Issuing Date | Weighted Average Coupon Rate | Weighted Average Yield at Issue | 30 yr yields: 30yr** | 30yr w/ Commission** | Yields reflective of Debt's Maturity: Debt Issue Maturity** | Ont Rate** | Ont Rate - w/ Commission** | Notes |
|---|---|---|---|---|---|---|---|---|
| February 9, 2018 | 3.526% | 3.548% | 3.23% | 3.25% | 15 year | 3.10% | 3.14% | Feb 9 Rate, Simple average between 10 and 20 year rates. |
| April 24, 2018 | 3.712% | 3.731% | 3.23% | 3.26% | 20 year | 3.22% | 3.25% | Apr 24 Rate |
| **Total** | **3.609%** | **3.629%** | | | | | | |

**Source: Fair Hydro Plan - Deliveries under Change of Law Process Agreement, February 8, 2018 and April 23, 2018.*

***Source: Corporate Finance Branch Interest Rate Snapshot based on ScotiaBank daily reports, semi-annual rate estimates. Commissions paid for dealers, based on historical one-time estimate. Subject to revision. Excludes additional costs Province may charge for on lending purposes.*

**ONTARIO POWER GENERATION INC.,**
**in its capacity as FSM**

**PROCESS CERTIFICATE**

*Certificate of the CFO and Treasurer pursuant to section 3.01 of the Change of Law Process Agreement*

**TO:** Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance (the "**Province**")

**RE:** Floating Rate Variable Funding Senior Notes, Series 2017-1 (the "**Series 2017-1 Senior Notes**") in the maximum aggregate principal amount of C$800,000,000, of which $75,990,000 will be drawn on April 20, 2018, resulting in a total drawn amount of $411,880,000

**AND RE:** Floating Rate Variable Funding Subordinated Notes, Series 2017-1 (the "**Series 2017-1 Subordinated Notes**") in the maximum aggregate principal amount of C$611,764,706 principal amount, of which $58,110,000 will be drawn on April 20, 2018, resulting in a total drawn amount of $314,967,000

**AND RE:** Floating Rate Variable Funding Junior Subordinated Notes, Series 2017-1 (the "**Series 2017-1 Junior Subordinated Notes**") in the maximum available aggregate principal amount of C$156,862,745, of which $14,900,000 will be drawn on April 20, 2018, resulting in a total drawn amount of $80,760,000 (the Series 2017-1 Junior Subordinated Notes together with the Series 2017-1 Senior Notes and the Series 2017-1 Subordinated Notes, the "**Funding Obligations**")

**AND RE:** Process Certificate of Ontario Power Generation Inc. in its capacity as FSM delivered pursuant to clause 3.01 of the Change of Law Process Agreement (as defined below) on December 21, 2017 (the "**Original Process Certificate**").

Reference is made to the Change of Law Process Agreement dated December 21, 2017 among the Province of Ontario and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have the meanings ascribed to such terms in the Change of Law Process Agreement.

Each of the undersigned, being the Chief Financial Officer and Treasurer of OPG acting in its capacity as FSM and holding the offices set forth under their names and signatures below, pursuant to and in accordance with clause 3.01 of the Change of Law Process Agreement, hereby certifies for and on behalf of OPG, in its capacity as Financial Services Manager, and not in such officer's personal capacity and intending that this certificate may be relied on by the addressees hereof without independent inquiry, that:

1. I have read and understand the provisions of the Change of Law Process Agreement and all other documents and materials necessary to enable me to deliver this certificate.

2. The material terms of the Funding Obligations, excluding the drawn principal amounts outstanding and identified on the preceding page, remain unchanged and are as described in Schedules A, B and C of the Original Process Certificate.

3. The Funding Obligations:

   (a) will arise under terms and conditions that are Substantially in the Form of the Reference Documentation applicable thereto;

   (b) in my opinion, are reasonably incurred or effected in compliance with the Act, the General Regulation, any other enactments related thereto and the Financing Plan;

   (c) are of a type and are on terms that a reasonably prudent financial services manager would incur in similar circumstances; and

   (d) reflect, in all material respects, arm's length terms and conditions.

4. No Disclosure Document was used in connection with the offering and sale of the Funding Obligations.

5. Any disclosure made in respect of any of the Funding Obligations (including any Disclosure Document, press release or other written communication prepared for dissemination to third parties in relation to any of the Funding Obligations) that refers to or describes the terms, effect or adherence of or to the Change of Law Process Agreement or the Change of Law Protection Agreement has been made available to the Province prior to use or dissemination, other than where such disclosure was substantially the same as a disclosure previously made.

6. No Breach Event has occurred on or prior to the date hereof, unless such Breach Event has been waived by the Province in writing.

7. At the time the Funding Obligations are incurred, the maximum aggregate payment amounts due or becoming due in the future in respect of Repayments under the Funding Obligations, together with all other outstanding amounts due or becoming due in the future in respect of Repayments under all Approved Obligations, do not exceed the Protection Agreement Maximum applicable on the date hereof.

**[Signature page follows]**

**DATED** April 16, 2018.

Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

Name: John Lee
Title: Vice President - Treasurer

- OPG was appointed the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017* (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC ~~is~~ was not nor expected to be involved in any of the planned financing~~s~~ by OPG for the Trust.
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.

- OPG was appointed the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017* (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC was ~~is~~ not involved and at this time has no direction to be involved in any of the planned financing~~s~~ by OPG for the Trust.]
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

- OPG was appointed the Financial Services Manager under the *Ontario Fair Hydro Plan Act, 2017* (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC is not involved in any of the planned financings by OPG for the Trust.
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has completed three equity injections related to OPG's asset purchases. This includes the interest costs related to the GA deferral as OPG would provide the carrying costs information to the IESO to be included as part of the regulatory assets sold to the Trust.

**From:** John Kim []
**To:** Shajee Kathirgamanathan [Shajee.Kathirgamanathan@ofina.on.ca]; Gavin He [Gavin.He@ofina.on.ca]; Atif Ali [Atif.Ali@ofina.on.ca]; Esther Jeon [Esther.Jeon@ofina.on.ca]; Salman Qadir [Salman.Qadir@ofina.on.ca]
**CC:** Bruno Amara [Bruno.Amara@ofina.on.ca]
**Subject:** FW: OPG 2018-2021 Business Plan
**Date:** Tuesday, February 13, 2018 13:13:38
**Attachment 1:** OPG 2018-2021 BPlan w Transmittal.blord to mstr.18feb12.pdf

---

Fyi.

**From:** Ronald Kwan
**Sent:** Tuesday, February 13, 2018 12:13 PM
**To:** John Kim <John.Kim@ofina.on.ca>; Bruno Amara <Bruno.Amara@ofina.on.ca>
**Cc:** Usman Zahid <Usman.Zahid@ofina.on.ca>; Francisco Chinchon <Francisco.Chinchon@ofina.on.ca>
**Subject:** FW: OPG 2018-2021 Business Plan

Hi,

Please review.

Ron

**From:** Calwell, Carolyn (ENERGY) [mailto:Carolyn.Calwell@ontario.ca]
**Sent:** February-13-18 12:08
**To:** Ronald Kwan <Ronald.Kwan@ofina.on.ca>
**Cc:** Talwar, Shruti (ENERGY) <Shruti.Talwar@ontario.ca>
**Subject:** FW: OPG 2018-2021 Business Plan

Hi Ron – wanted to get this over to you. Shruti will also share with staff. We are just beginning our review.

Carolyn

**From:** KING Catriona -OFFCORPSEC [mailto:catriona.king@opg.com]
**Sent:** February 12, 2018 7:14 PM
**To:** Thibeault, Glenn (ENERGY)
**Cc:** Imbrogno, Serge (ENERGY); Calwell, Carolyn (ENERGY); LYASH Jeffrey -PRESIDENT; Bernard Lord; LORD Bernard -BOARDCHAIR; HARTWICK Ken -FINANCE; ROWE Jennifer -CORPAFFAIRS
**Subject:** OPG 2018-2021 Business Plan

Dear Minister Thibeault,

Please see attached correspondence, sent on behalf of OPG Board Chair Bernard Lord, submitting OPG's 2018-2021 Business Plan for your concurrence, per the Memorandum of Agreement with the shareholder.
thx

**Catriona King | Vice President, Corporate Secretary | Ontario Power Generation Inc.**
700 University Avenue, Suite H19 D26, Toronto, Ontario M5G 1X6 | W: 416.592.4474 | C: 416.524.4421| F: 416.592.4555 |
| E: **catriona.king@opg.com**

**Good Governance is Good Business**

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

**Tel: 416-592-2115**
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

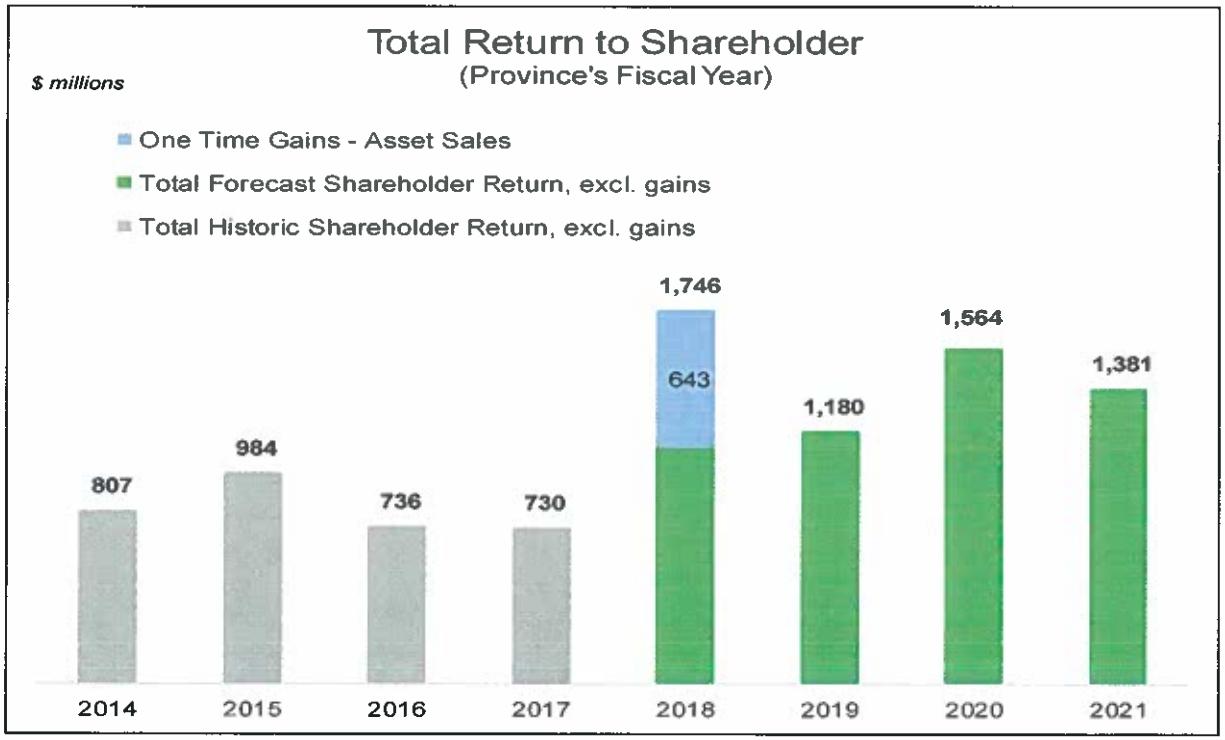
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

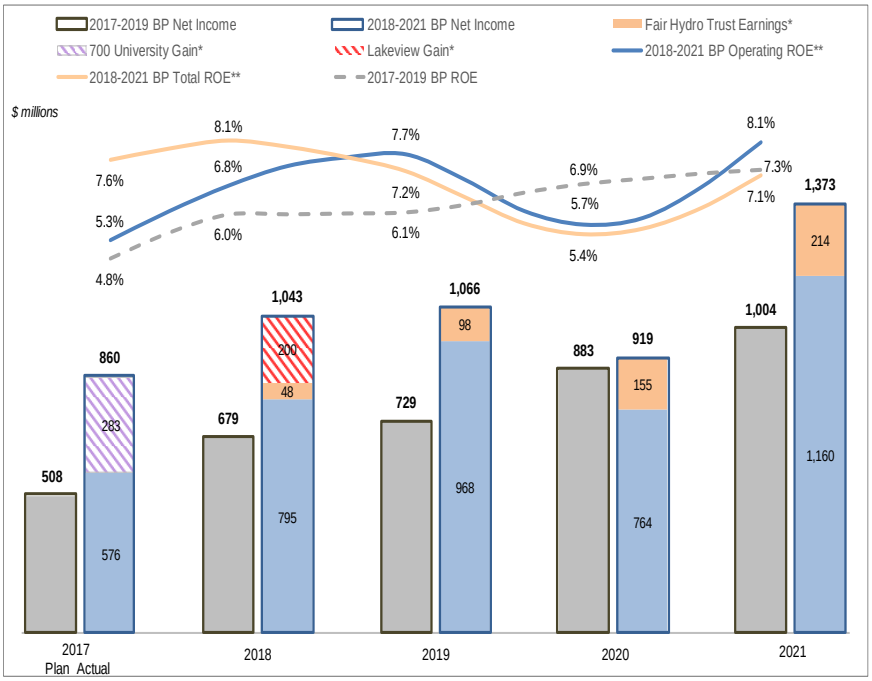
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

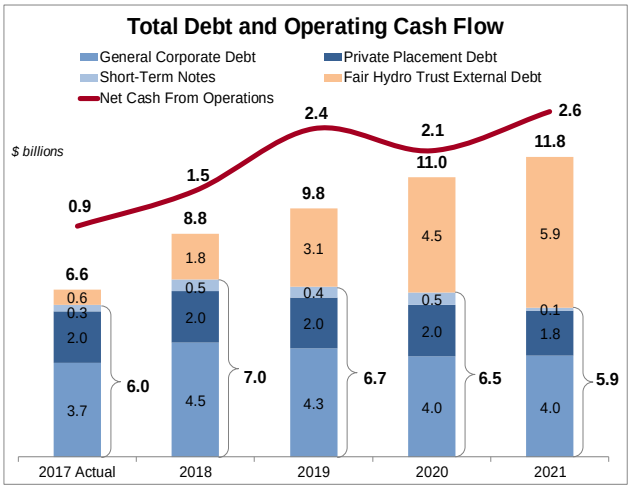
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

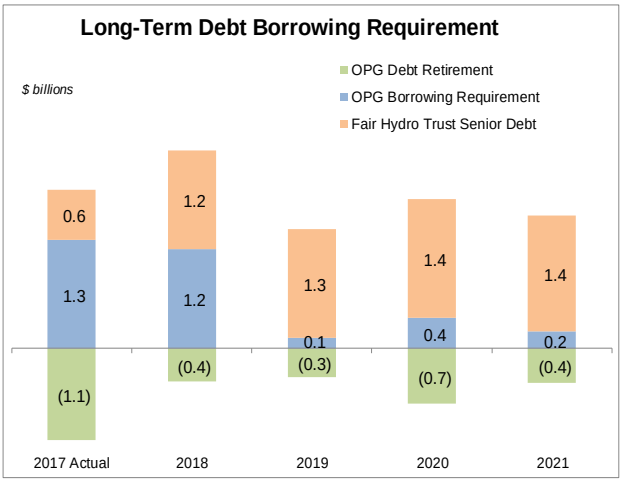
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

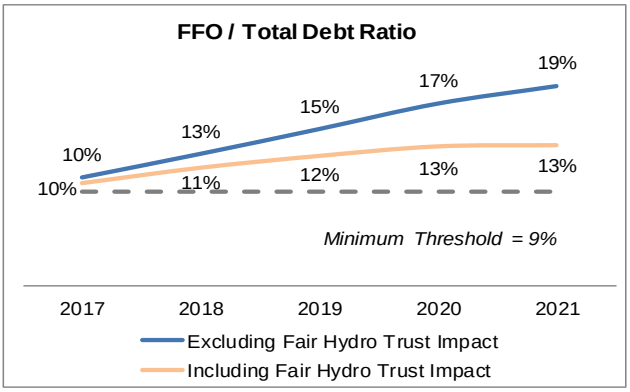


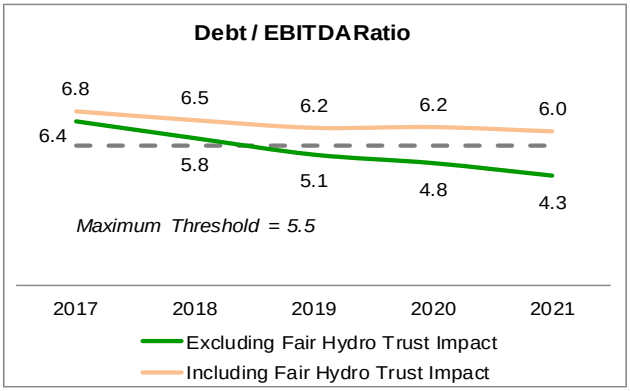

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



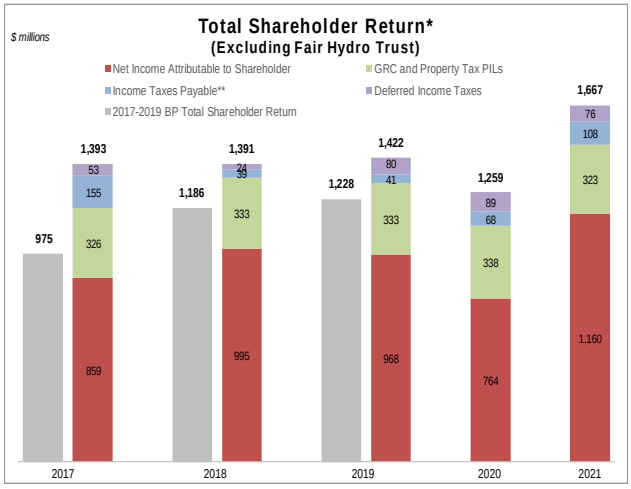

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

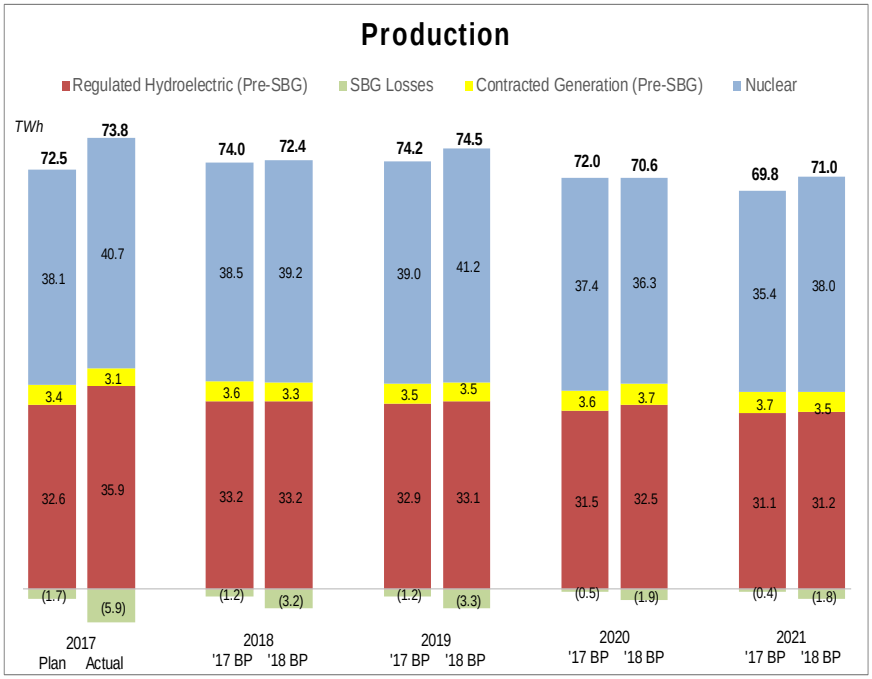
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

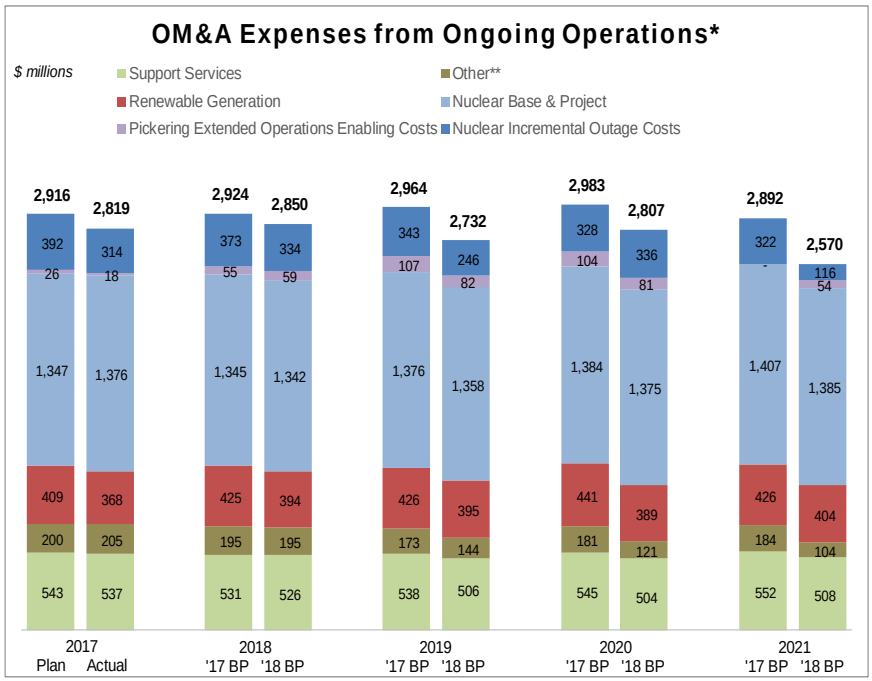
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

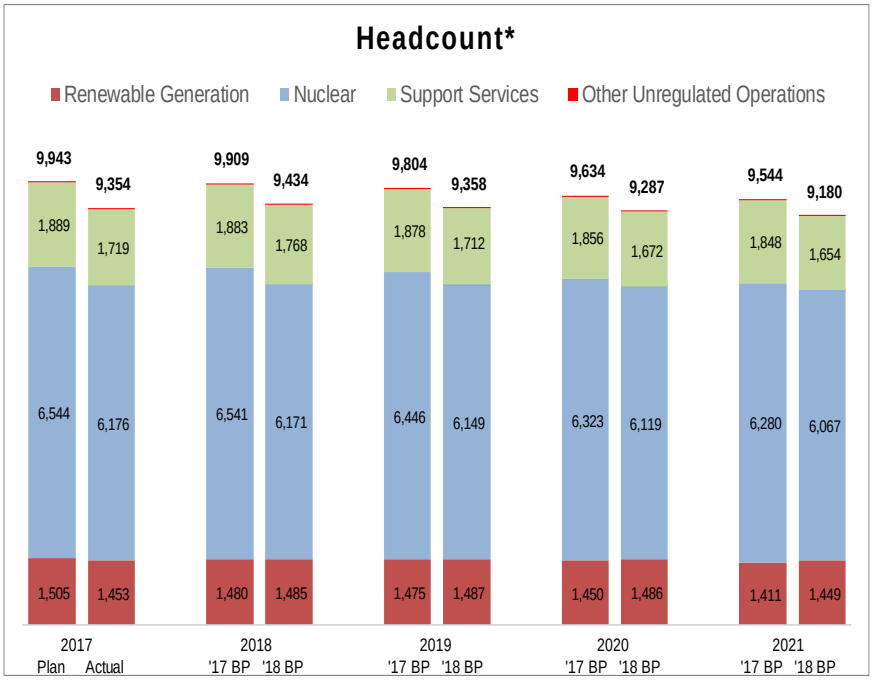
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

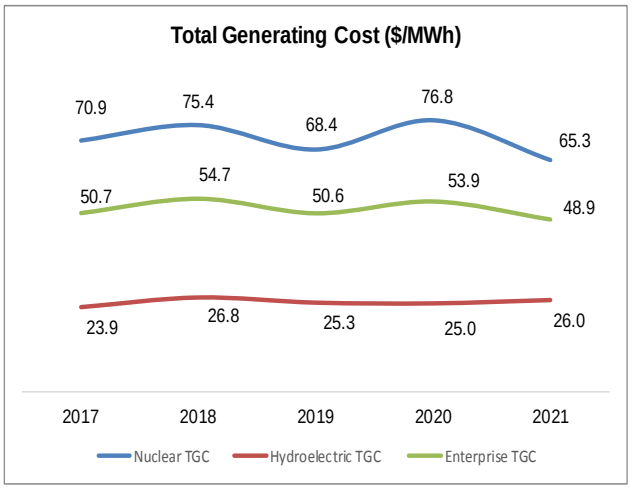
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

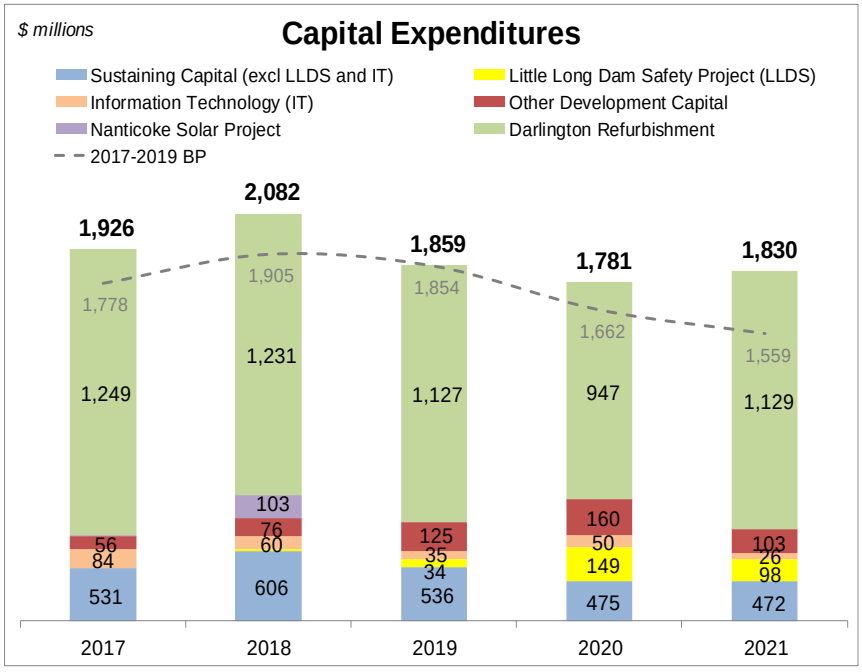
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

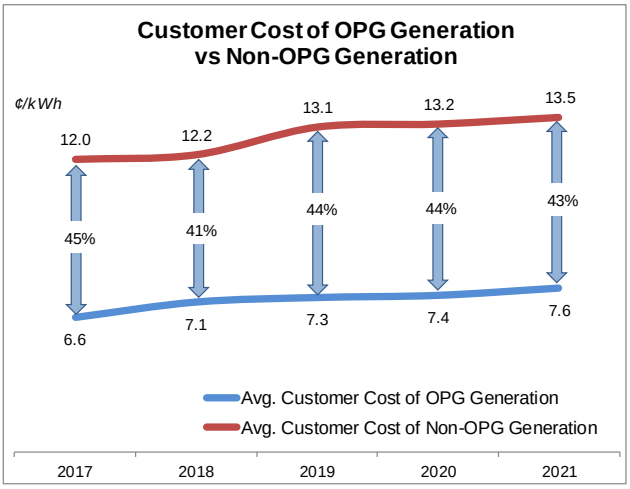
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 73 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

# FAIR HYDRO SPREADS

**Week of April 19, 2018**

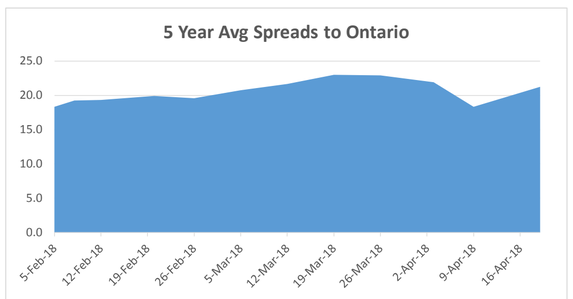
## Senior Note

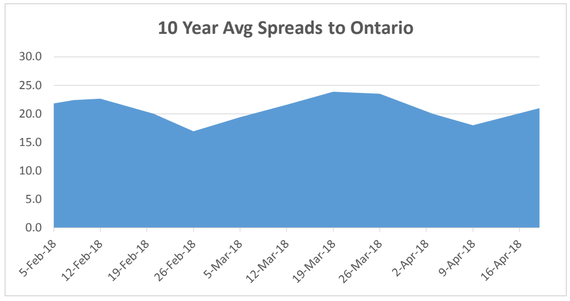
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 35.4 | 30.7 | 24.8 | 21.0 | 21.3 | 22.4 |

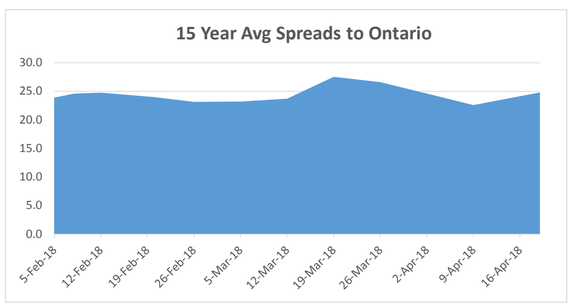
| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 112.6 | 107.0 | 100.1 | 88.0 | 66.5 | 51.0 |
| Last Week's | 113.4 | 110.1 | 103.0 | 90.7 | 68.4 | 52.5 |
| Change | -0.8 | -3.1 | -2.8 | -2.7 | -1.9 | -1.5 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *RBC* | *BMO* | *GS* | *GS* | *TD* | *TD* |
| | 106.0 | 107.0 | 97.0 | 77.0 | 60.0 | 45.0 |
| Maximum | *Scotia* | *BMO* | *RBC* | *RBC* | *RBC* | *RBC* |
| | 117.0 | 107.0 | 106.0 | 96.0 | 74.0 | 56.0 |




## Sub Note

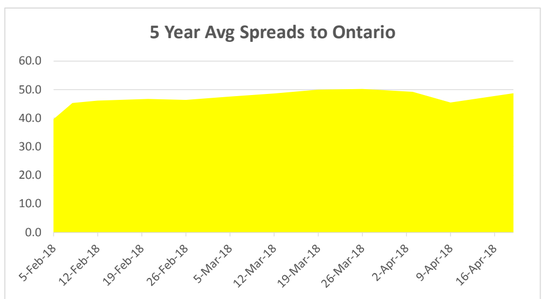
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 67.3 | 62.2 | 55.5 | 50.3 | 48.8 | 49.9 |

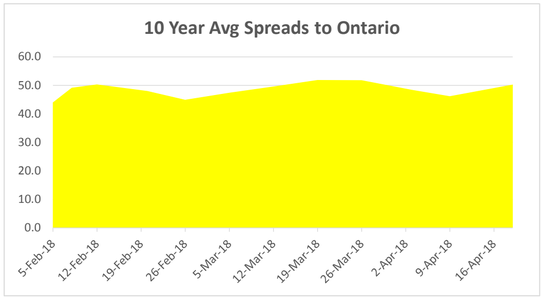
31.6

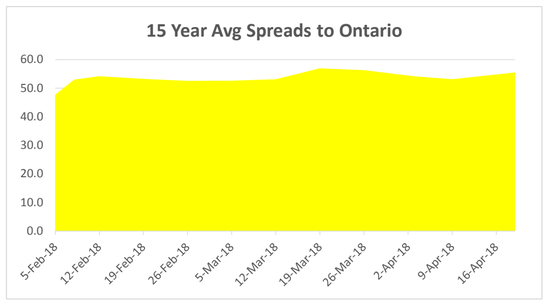
| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 144.5 | 138.6 | 130.9 | 117.3 | 94.0 | 78.5 |
| Last Week's | 144.3 | 140.6 | 132.7 | 119.0 | 95.6 | 79.7 |
| Change | 0.2 | -2.1 | -1.8 | -1.7 | -1.6 | -1.2 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *CIBC* | *GS* | *CIBC* | *CIBC* | *NBF* | *NBF* |
| | 137.5 | 132.0 | 126.0 | 108.0 | 88.0 | 73.0 |
| Maximum | *GS* | *BMO* | *BMO* | *RBC* | *RBC* | *NBF* |
| | 152.0 | 146.0 | 138.0 | 128.0 | 106.0 | 88.0 |




## Junior Sub Note

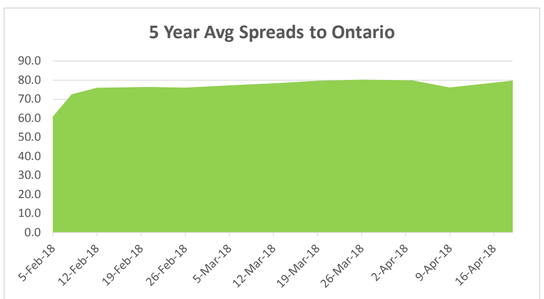
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 109.4 | 103.7 | 95.5 | 86.9 | 79.8 | 81.1 |

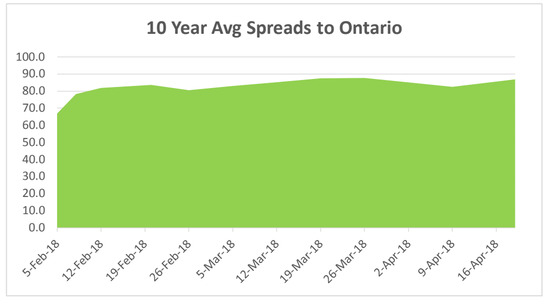
73.0

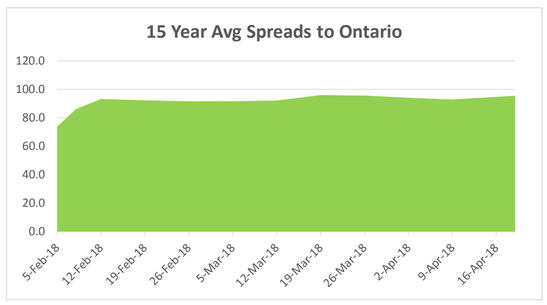
| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 186.6 | 180.0 | 170.9 | 153.9 | 125.0 | 109.7 |
| Last Week's | 185.7 | 181.6 | 172.4 | 155.3 | 126.3 | 110.5 |
| Change | 0.9 | -1.6 | -1.6 | -1.4 | -1.3 | -0.8 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *CIBC* | *CIBC* | *CIBC* | *BMO* | *NBF* | *NBF* |
| | 164.5 | 161.0 | 153.0 | 135.0 | 107.0 | 92.0 |
| Maximum | *BMO* | *BMO* | *BMO* | *GS* | *RBC* | *RBC* |
| | 221.0 | 217.0 | 205.0 | 172.0 | 142.0 | 124.0 |



# FAIR HYDRO SPREADS

**Week of April 19, 2018**

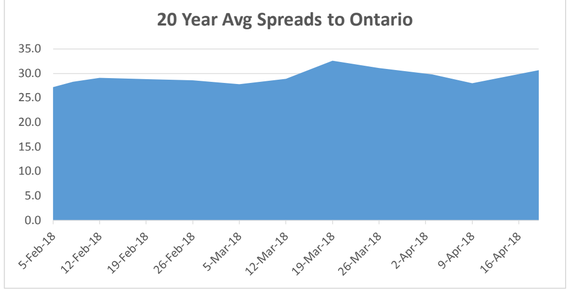
## Senior Note

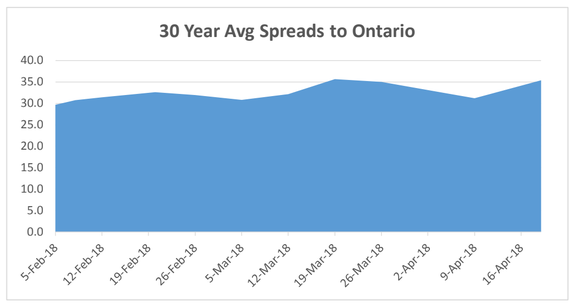
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 35.4 | 30.7 | 24.8 | 21.0 | 21.3 | 22.4 |

| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 112.6 | 107.0 | 100.1 | 88.0 | 66.5 | 51.0 |
| Last Week's | 113.4 | 110.1 | 103.0 | 90.7 | 68.4 | 52.5 |
| Change | -0.8 | -3.1 | -2.8 | -2.7 | -1.9 | -1.5 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *RBC* | *BMO* | *GS* | *GS* | *TD* | *TD* |
| | 106.0 | 107.0 | 97.0 | 77.0 | 60.0 | 45.0 |
| Maximum | *Scotia* | *BMO* | *RBC* | *RBC* | *RBC* | *RBC* |
| | 117.0 | 107.0 | 106.0 | 96.0 | 74.0 | 56.0 |




## Sub Note

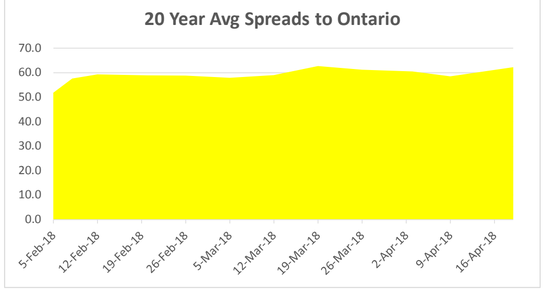
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 67.3 | 62.2 | 55.5 | 50.3 | 48.8 | 49.9 |

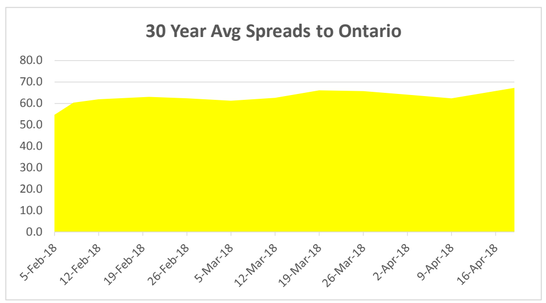
31.6

| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 144.5 | 138.6 | 130.9 | 117.3 | 94.0 | 78.5 |
| Last Week's | 144.3 | 140.6 | 132.7 | 119.0 | 95.6 | 79.7 |
| Change | 0.2 | -2.1 | -1.8 | -1.7 | -1.6 | -1.2 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *CIBC* | *GS* | *CIBC* | *CIBC* | *NBF* | *NBF* |
| | 137.5 | 132.0 | 126.0 | 108.0 | 88.0 | 73.0 |
| Maximum | *GS* | *BMO* | *BMO* | *RBC* | *RBC* | *NBF* |
| | 152.0 | 146.0 | 138.0 | 128.0 | 106.0 | 88.0 |




## Junior Sub Note

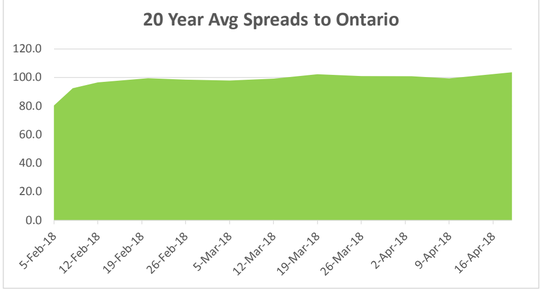
| Average Spreads to Ontario | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 109.4 | 103.7 | 95.5 | 86.9 | 79.8 | 81.1 |

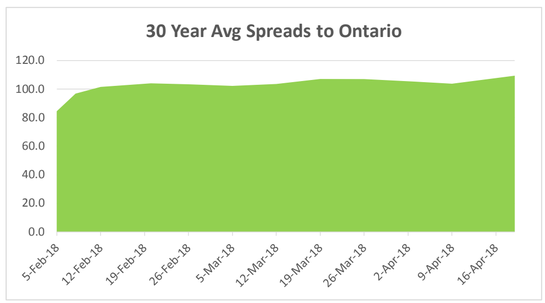
73.0

| Average Fair Hydro Spreads to GoC curve | | | | | |
|---|---|---|---|---|---|
| 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| 186.6 | 180.0 | 170.9 | 153.9 | 125.0 | 109.7 |
| Last Week's | 185.7 | 181.6 | 172.4 | 155.3 | 126.3 | 110.5 |
| Change | 0.9 | -1.6 | -1.6 | -1.4 | -1.3 | -0.8 |

**Spreads to GoC**

| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|---|---|
| Minimum | *CIBC* | *CIBC* | *CIBC* | *BMO* | *NBF* | *NBF* |
| | 164.5 | 161.0 | 153.0 | 135.0 | 107.0 | 92.0 |
| Maximum | *BMO* | *BMO* | *BMO* | *GS* | *RBC* | *RBC* |
| | 221.0 | 217.0 | 205.0 | 172.0 | 142.0 | 124.0 |



**Indicative New Issue Spreads**
**Week of April 19, 2018**

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | BMO | BMO | BMO | BMO | BMO | BMO | CIBC | CIBC | CIBC | CIBC | CIBC | CIBC | GS | GS | GS | GS | GS | GS | NBF | NBF |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
| | Current | | | | | | Current | | | | | | Current | | | | | | | |
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Sep-22 | 01-Sep-20 | 01-Dec-48 | 1-Jun-37 | 1-Jun-33 | 1-Jun-28 | 01-Jun-25 | 01-Mar-23 | 1DEC48 | 1JUN37 and 1JUN41 | 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 2.75% | 0.75% | 2.75% | 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | 2.75% | 5.00% | 5.75% | 2.00% | | | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% | 2.37% | 2.33% | 2.18% | 1.99% | 2.43% | 2.44% | 2.37% | 2.32% | 2.26% | 2.15% | 2.43% | 2.44% | 2.39% | 2.31% | | | 2.40% | 2.39% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 1.9 | 1.7 | 1.5 | 6.9 | 0.0 | 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0.0 | 0.6 | 4.9 | 0.8 | | | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 108 | 107 | 100 | 90 | 66 | 50 | 111 | 107 | 99 | 81 | 62 | 48 | 117 | 107 | 97 | 77.0 | | | 115 | 107 |
| Re-Offered Yield | 3.51% | 3.49% | 3.39% | 3.25% | 2.85% | 2.56% | 3.53% | 3.52% | 3.36% | 3.13% | 2.88% | 2.65% | 3.60% | 3.51% | 3.36% | 3.08% | | | 3.55% | 3.46% |
| Commission (bp) | 2.7 | 3.4 | 3.4 | 4.6 | 7.5 | 6.9 | 2.7 | 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | 1.7 | 2.5 | 3.3 | 5.0 | | | 2.7 | 3.5 |
| **All-in Yield** | **3.54%** | **3.52%** | **3.43%** | **3.30%** | **2.92%** | **2.63%** | **3.56%** | **3.55%** | **3.38%** | **3.15%** | **2.90%** | **2.66%** | **3.62%** | **3.54%** | **3.39%** | **3.13%** | | | **3.58%** | **3.49%** |
| **All-in Spread to GoC Curve (bp)** | **110.66** | **110.43** | **103.37** | **94.64** | **73.45** | **56.88** | **113.23** | **109.73** | **101.40** | **83.07** | **63.76** | **49.22** | **118.67** | **109.50** | **100.33** | **82.00** | | | **117.73** | **110.50** |

| Primary Comparable (S&P/Moody's/ DBRS) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| Province of Ontario (AA- / Aa2 / AA(L)) | 75 | 75 | 73 | 65 | 43 | 28 | 75 | 75 | 73 | 65 | 46 | 28 | 74 | 75 | 71 | 67 | | | 78 | 79 |

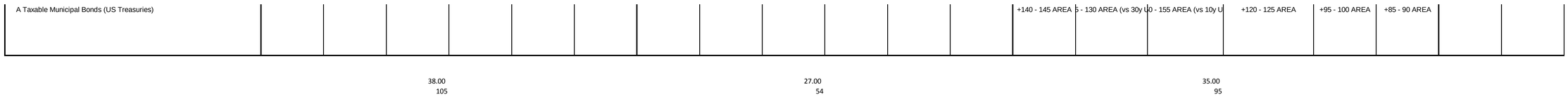
| Other Comparables (S&P/Moody's/ DBRS) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| Canada Mortgage & Housing Corp (AAA/Aaa/AAA) | | | | | | | | | | | | | | | | | | | | |
| City of Toronto (AA/Aa1/AA) | | | | | | | | | | | | | | | | | | | | |
| Hydro One Inc. (A(H)/A3/A) | | | | | | | | | | | | | | | | | | | | |
| Ontario Power Generation Inc. (A(low)/-/BBB+) | | | | | | | 167 | -- | -- | 120 | 80 | 64 | | | | | | | | |
| Toronto Hydro Corporation (A/-/A) | | | | | | | 132 | -- | -- | 96 | 69 | 57 | | | | | | | | |
| Canadian National Railway Co (A/A2/A) | | | | | | | | | | | | | | | | | | | | |
| Greater Toronto Airports Authority (A(high)/Aa3/A+) | | | | | | | | | | | | | | | | | | | | |
| NAV Canada (AA(low)/Aa2/AA-) | 99 | 0 | 0 | 82 | 57 | 52 | | | | | | | | | | | | | | |
| OPB Finance Trust (AA+/-/AA(H)) | | | | | | | | | | | | | | | | | | | | |
| Covered Bond - Bank (AAA/Aaa/AAA) | | | | | | | | | | | | | | | | | | | | |
| Schedule I Bank deposit notes (A1-Aa2 ; A-AA- ; AA) | | | | | | | | | | | | | | | | | | | 140 | 134 |
| Schedule I Bank covered bonds (Aaa ; AAA ; AAA) | | | | | | | | | | | | | | | | | | | 123 | 117 |
| Schedule I Bank ABS (Aaa ; AAA ; AAA) | | | | | | | | | | | | | | | | | | | 145 | 138 |
| ABS - Eagle 2017-1 A (AAA) | 0 | 0 | 0 | 0 | 88 | 0 | | | | | | | | | | | | | | |
| ABS - BMO Fortified (HELOC ABS) (AAA/AAA) | 0 | 0 | 0 | 0 | 82 | 67 | | | | | | | | | | | | | | |
| MBS - BAML NHA MBS (AAA/AAA) | 0 | 0 | 0 | 0 | 67 | 52 | | | | | | | | | | | | | | |
| CMBs: (AAA/Aaa/AAA) | 0 | 0 | 41 | 36 | 29 | 17 | | | | | | | | | | | | | | |
| PSP Investments (AAA/Aaa/AAA) | 0 | 0 | 0 | 71 | 48 | 32 | | | | | | | | | | | | | | |
| CPP Investment Board (AAA/Aaa/AAA) | 91 | 0 | 0 | 71 | 48 | 32 | | | | | | | | | | | | | | |
| BMO (Senior) (A+/A1/AA) | 122 | 0 | 0 | 97 | 82 | 70 | | | | | | | | | | | | | | |
| Nova Scotia Power (BBB+ / - / A(l)) | | | | | | | 150 | -- | -- | 107 | 78 | 63 | | | | | | | | |
| FortisAlberta (A- / Baa1 / A(l)) | | | | | | | 138 | -- | -- | 98 | 70 | -- | | | | | | | | |
| Brookfield Renewable Energy Partners (BBB / - / BBB(H)) | | | | | | | 245 | -- | -- | 180 | 127 | 105 | | | | | | | | |
| Bruce Power (BBB / Baa2 / BBB) | | | | | | | 212 | -- | -- | 152 | 114 | -- | | | | | | | | |
| City of Toronto (- / Aa1 / AA) | | | | | | | 100 | 101 | -- | 82 | -- | -- | | | | | | | | |
| BNS - Denior Deposit Notes | | | | | | | | | | | | | | | | | | | | |
| Golden Credit Card Trust | | | | | | | | | | | | | | | | | | | | |
| Master Credit Card Trust | | | | | | | | | | | | | | | | | | | | |
| AAA CMBS (USD Swaps) | | | | | | | | | | | | | | | | 85 bps area | | | | |
| AAA Taxable Municipal Bonds (US Treasuries) | | | | | | | | | | | | | +95 AREA | 0-85 AREA (vs 30y U | 95-110 AREA (vs 10y U | +75-80 AREA | +65 - 70 AREA | +55 - 60 AREA | | |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 01-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Sep-22 | 01-Sep-20 | 01-Dec-48 | 01-Jun-37 | 1-Jun-33 | 1-Jun-28 | 01-Jun-25 | 01-Mar-23 | 1DEC48 | 1JUN37 and 1JUN41 | 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 2.75% | 0.75% | 2.75% | 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | 2.75% | 4.00% | 5.75% | 2.00% | | | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% | 2.37% | 2.33% | 2.18% | 1.99% | 2.43% | 2.44% | 2.37% | 2.32% | 2.26% | 2.15% | 2.43% | 2.44% | 2.39% | 2.31% | | | 2.40% | 2.39% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 1.9 | 1.7 | 1.5 | 6.9 | 0.0 | 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0.0 | 0.7 | 4.9 | 0.8 | | | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 147 | 146 | 138 | 119 | 91 | 75 | 138 | 134 | 126 | 108 | 89 | 75 | 152 | 142 | 132 | 112 | | | 140 | 132 |
| Re-Offered Yield | 3.90% | 3.88% | 3.77% | 3.54% | 3.10% | 2.81% | 3.80% | 3.79% | 3.63% | 3.40% | 3.15% | 2.92% | 3.95% | 3.86% | 3.71% | 3.43% | | | 3.80% | 3.71% |
| Commission (bp) | 2.8 | 3.5 | 3.5 | 4.7 | 7.5 | 6.9 | 2.7 | 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | 1.7 | 2.5 | 3.3 | 5.0 | | | 2.7 | 3.5 |
| **All-in Yield** | **3.93%** | **3.92%** | **3.81%** | **3.59%** | **3.17%** | **2.88%** | **3.83%** | **3.82%** | **3.65%** | **3.42%** | **3.17%** | **2.93%** | **3.97%** | **3.89%** | **3.71%** | **3.48%** | | | **3.83%** | **3.74%** |
| **All-in Spread to GoC Curve (bp)** | **149.79** | **149.55** | **141.45** | **123.70** | **98.49** | **81.90** | **140.23** | **136.73** | **128.40** | **110.07** | **90.76** | **76.22** | **153.67** | **144.50** | **135.33** | **117.00** | | | **142.73** | **135.50** |

| Other Comparables (S&P/Moody's/ DBRS) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| RBC Sr-Sub. | | | | | | | | | | | | | | | | | | | | |
| Highway 407 (A, A) | | | | | | | | | | | | | | | | | | | 130 | 123 |
| NAV Canada (AA-, AA low) | | | | | | | | | | | | | | | | | | | 100 | 97 |
| GTAA (Aa3, A+) | | | | | | | | | | | | | | | | | | | 100 | 97 |
| Hydro One (A3/A/A high) | | | | | | | | | | | | | | | | | | | 135 | 129 |
| ABS - BMO Fortified (HELOC ABS) (AA/AA) | 0 | 0 | 0 | 0 | 0 | 87 | | | | | | | | | | | | | | |
| ABS - Ford Floorplan Auto Securitization (AA / AA / AA) | 0 | 0 | 0 | 0 | 0 | 102 | | | | | | | | | | | | | | |
| BMO (Senior) (A+/A1/AA) | 122 | 0 | 0 | 97 | 82 | 70 | | | | | | | | | | | | | | |
| Nav Canada (sub) (AA-/Aa2/AAL) | 99 | 0 | 0 | 82 | 57 | 52 | | | | | | | | | | | | | | |
| City of Toronto (AA / Aa1 / AA) | 96 | 95 | 93 | 82 | 59 | 42 | | | | | | | | | | | | | | |
| Bank ABS (AAA / - / AAA) | | | | | | | -- | -- | -- | -- | 82 | 68 | | | | | | | | |
| Auto ABS (Ford) (AAA / Aaa / AAA) | | | | | | | -- | -- | -- | -- | 91 | 78 | | | | | | | | |
| NHA MBS (AAA / Aaa / AAA) | | | | | | | -- | -- | -- | -- | 48 | 37 | | | | | | | | |
| AA CMBS (USD Swaps) | | | | | | | | | | | | | | | | 120 - 125 bps AREA | | | | |
| AA Taxable Municipal Bonds (US Treasuries) | | | | | | | | | | | | | +115 - 120 AREA | 100 AREA (vs 30y US | 5 - 130 AREA (vs 10y U | +100 - 105 AREA | +75 - 80 AREA | +60 - 65 AREA | | |

| Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Sep-22 | 01-Sep-20 | 01-Dec-48 | 1-Jun-37 | 1-Jun-33 | 1-Jun-28 | 01-Jun-25 | 01-Mar-23 | 1DEC48 | 1JUN37 and 1JUN41 | 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 2.75% | 0.75% | 2.75% | 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | 2.75% | 4.00% | 5.75% | 2.00% | | | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% | 2.37% | 2.33% | 2.18% | 1.99% | 2.43% | 2.44% | 2.37% | 2.32% | 2.26% | 2.15% | 2.43% | 2.44% | 2.39% | 2.31% | | | 2.40% | 2.39% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 1.9 | 1.7 | 1.5 | 6.9 | 0.0 | 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0.0 | 0.7 | 4.9 | 0.8 | | | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 221 | 217 | 205 | 169 | 135 | 120 | 165 | 161 | 153 | 135 | 116 | 102 | 212 | 202 | 192 | 172 | | | 170 | 162 |
| Re-Offered Yield | 4.64% | 4.59% | 4.44% | 4.04% | 3.54% | 3.26% | 4.07% | 4.06% | 3.90% | 3.67% | 3.42% | 3.19% | 4.55% | 4.46% | 4.31% | 4.03% | | | 4.10% | 4.01% |
| Commission (bp) | 2.9 | 3.7 | 3.5 | 4.8 | 7.6 | 6.9 | 2.7 | 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | 1.7 | 2.5 | 3.3 | 5.0 | | | 2.7 | 3.5 |
| **All-in Yield** | **4.67%** | **4.63%** | **4.48%** | **4.09%** | **3.62%** | **3.33%** | **4.10%** | **4.09%** | **3.92%** | **3.69%** | **3.44%** | **3.20%** | **4.57%** | **4.49%** | **4.31%** | **4.08%** | | | **4.13%** | **4.04%** |
| **All-in Spread to GoC Curve (bp)** | **223.89** | **220.67** | **208.55** | **173.78** | **142.56** | **126.94** | **167.23** | **163.73** | **155.40** | **137.07** | **117.76** | **103.22** | **213.67** | **204.50** | **195.33** | **177.00** | | | **172.73** | **165.50** |

| Other Comparables (S&P/Moody's/ DBRS) | BMO | | | | | | CIBC | | | | | | GS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year |
| **Ontario Power Generation (BBB+/A low)** | | | | | | | | | | | | | | | | | | | 155.0 | 149.0 |
| **Highway 407 (A, A)** | | | | | | | | | | | | | | | | | | | 130.0 | 123.3 |
| **Enbridge Gas Distribution (A-, A)** | | | | | | | | | | | | | | | | | | | 130.0 | 124.8 |
| **Hydro One (A3/A/A high)** | | | | | | | | | | | | | | | | | | | 135.0 | 129.0 |
| **Schedule 1 Bank ABS (A)** | | | | | | | | | | | | | | | | | | | 200.0 | 193.3 |
| ABS - Eagle 2017-1 Sub A Rated Tranche | - | - | - | - | 153.0 | - | | | | | | | | | | | | | | |
| ABS - BMO Fortified Sub A Rated Tranche | - | - | - | - | 135.0 | - | | | | | | | | | | | | | | |
| Hydro One (A/A3/AH) | 137.0 | - | - | 100.0 | 75.0 | 62.0 | | | | | | | | | | | | | | |
| OPG (BBB+/-/AL) | 166.0 | - | - | 119.0 | 94.0 | 81.0 | | | | | | | | | | | | | | |
| 10-year A CMBS (USD Swaps) | | | | | | | | | | | | | | | | 160 -170 bps AREA | | | | |


A Taxable Municipal Bonds (US Treasuries)
+140 - 145 AREA
5 - 130 AREA (vs 30y U
0 - 155 AREA (vs 10y U
+120 - 125 AREA
+95 - 100 AREA
+85 - 90 AREA
38.00
105
27.00
54
35.00
95

**Indicative New Issue Spreads**
**Week of April 19, 2018**

NBF *NBF* *NBF* NBF

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | NBF | | | |
|---|---|---|---|---|
| | Current | | | |
| | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 1-Jun-33 | 1-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| Benchmark Canada Bond Coupon | 5.75% | 1.00% | 2.75% | 0.75% |
| Benchmark Yield | 2.35% | 2.30% | 2.14% | 2.02% |
| Curve Adjustment (bp) | 0.0 | 0.0 | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 103 | 90.00 | 67 | 52 |
| Re-Offered Yield | 3.38% | 3.20% | 2.81% | 2.54% |
| Commission (bp) | 3.9 | 4.7 | 7.6 | 8.7 |
| **All-in Yield** | **3.42%** | **3.25%** | **2.89%** | **2.63%** |
| **All-in Spread to GoC Curve (bp)** | **106.86** | **94.72** | **74.57** | **60.72** |

| Primary Comparable (S&P/Moody's/ DBRS) | NBF | | | |
|---|---|---|---|---|
| Spread to GoC Curve (bp) | 15-year | 10-year | 5-year | 3-year |
| Province of Ontario (AA- / Aa2 / AA(L)) | 76 | 67 | 44 | 28 |

| Other Comparables (S&P/Moody's/ DBRS) | NBF | | | |
|---|---|---|---|---|
| Spread to GoC Curve (bp) | 15-year | 10-year | 5-year | 3-year |
| Canada Mortgage & Housing Corp (AAA/Aaa/AAA) | | | | |
| City of Toronto (AA/Aa1/AA) | | | | |
| Hydro One Inc. (A(H)/A3/A) | | | | |
| Ontario Power Generation Inc. (A(low)/-/BBB+) | | | | |
| Toronto Hydro Corporation (A/-/A) | | | | |
| Canadian National Railway Co (A/A2/A) | | | | |
| Greater Toronto Airports Authority (A(high)/Aa3/A+) | | | | |
| NAV Canada (AA(low)/Aa2/AA-) | | | | |
| OPB Finance Trust (AA+/-/AA(H)) | | | | |
| Covered Bond - Bank (AAA/Aaa/AAA) | | | | |
| Schedule I Bank deposit notes (A1-Aa2 ; A-AA- ; AA) | 117 | 100 | 80 | 70 |
| Schedule I Bank covered bonds (Aaa ; AAA ; AAA) | 100 | 85 | 65 | 57 |
| Schedule I Bank ABS (Aaa ; AAA ; AAA) | 119 | 100 | 80 | 70 |
| ABS - Eagle 2017-1 A (AAA) | | | | |
| ABS - BMO Fortified (HELOC ABS) (AAA/AAA) | | | | |
| MBS - BAML NHA MBS (AAA/AAA) | | | | |
| CMBs: (AAA/Aaa/AAA) | | | | |
| PSP Investments (AAA/Aaa/AAA) | | | | |
| CPP Investment Board (AAA/Aaa/AAA) | | | | |
| BMO (Senior) (A+/A1/AA) | | | | |
| Nova Scotia Power (BBB+ / - / A(l)) | | | | |
| FortisAlberta (A- / Baa1 / A(l)) | | | | |
| Brookfield Renewable Energy Partners (BBB / - / BBB(H)) | | | | |
| Bruce Power (BBB / Baa2 / BBB) | | | | |
| City of Toronto (- / Aa1 / AA) | | | | |
| BNS - Denior Deposit Notes | | | | |
| Golden Credit Card Trust | | | | |
| Master Credit Card Trust | | | | |
| AAA CMBS (USD Swaps) | | | | |
| AAA Taxable Municipal Bonds (US Treasuries) | | | | |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | NBF | | | |
|---|---|---|---|---|
| | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 01-Jun-33 | 01-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| Benchmark Canada Bond Coupon | 5.75% | 1.00% | 2.75% | 0.75% |
| Benchmark Yield | 2.35% | 2.30% | 2.14% | 2.02% |
| Curve Adjustment (bp) | 0.0 | 0.0 | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 126 | 112 | 88 | 73 |
| Re-Offered Yield | 3.61% | 3.42% | 3.02% | 2.75% |
| Commission (bp) | 3.9 | 4.7 | 7.6 | 8.7 |
| **All-in Yield** | **3.65%** | **3.47%** | **3.10%** | **2.84%** |
| **All-in Spread to GoC Curve (bp)** | **129.86** | **116.72** | **95.57** | **81.72** |

| Other Comparables (S&P/Moody's/ DBRS) | NBF | | | |
|---|---|---|---|---|
| Spread to GoC Curve (bp) | 15-year | 10-year | 5-year | 3-year |
| RBC Sr-Sub. | | | | |
| Highway 407 (A, A) | 104 | 85 | 65 | 55 |
| NAV Canada (AA-, AA low) | 89 | 80 | 55 | 45 |
| GTAA (Aa3, A+) | 89 | 80 | 55 | 45 |
| Hydro One (A3/A/A high) | 112 | 95 | 70 | 60 |
| ABS - BMO Fortified (HELOC ABS) (AA/AA) | | | | |
| ABS - Ford Floorplan Auto Securitization (AA / AA / AA) | | | | |
| BMO (Senior) (A+/A1/AA) | | | | |
| Nav Canada (sub) (AA-/Aa2/AAL) | | | | |
| City of Toronto (AA / Aa1 / AA) | | | | |
| Bank ABS (AAA / - / AAA) | | | | |
| Auto ABS (Ford) (AAA / Aaa / AAA) | | | | |
| NHA MBS (AAA / Aaa / AAA) | | | | |
| AA CMBS (USD Swaps) | | | | |
| AA Taxable Municipal Bonds (US Treasuries) | | | | |

| Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2) | NBF | | | |
|---|---|---|---|---|
| | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 1-Jun-33 | 1-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| Benchmark Canada Bond Coupon | 5.75% | 1.00% | 2.75% | 0.75% |
| Benchmark Yield | 2.35% | 2.30% | 2.14% | 2.02% |
| Curve Adjustment (bp) | 0.0 | 0.0 | 0.0 | 0.0 |
| Spread to GoC Curve (bp) | 156 | 135 | 107 | 92 |
| Re-Offered Yield | 3.91% | 3.65% | 3.21% | 2.94% |
| Commission (bp) | 3.9 | 4.7 | 7.6 | 8.7 |
| **All-in Yield** | **3.95%** | **3.70%** | **3.29%** | **3.03%** |
| **All-in Spread to GoC Curve (bp)** | **159.86** | **139.72** | **114.57** | **100.72** |

| Other Comparables (S&P/Moody's/ DBRS) | NBF | | | |
|---|---|---|---|---|
| Spread to GoC Curve (bp) | 15-year | 10-year | 5-year | 3-year |
| **Ontario Power Generation (BBB+/A low)** | 132.0 | 115.0 | 90.0 | 75.0 |
| **Highway 407 (A, A)** | 104.1 | 85.0 | 65.0 | 55.0 |
| **Enbridge Gas Distribution (A-, A)** | 109.9 | 95.0 | 75.0 | 60.0 |
| **Hydro One (A3/A/A high)** | 112.0 | 95.0 | 70.0 | 60.0 |
| **Schedule 1 Bank ABS (A)** | 174.1 | 155.0 | 135.0 | 120.0 |
| ABS - Eagle 2017-1 Sub A Rated Tranche | | | | |
| ABS - BMO Fortified Sub A Rated Tranche | | | | |
| Hydro One (A/A3/AH) | | | | |
| OPG (BBB+/-/AL) | | | | |
| 10-year A CMBS (USD Swaps) | | | | |

| | | | | |
|---|---|---|---|---|
| A Taxable Municipal Bonds (US Treasuries) | | | | |

**Indicative New Issue Spreads**
**Week of April 19, 2018**

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | RBC | RBC | RBC | *RBC* | *RBC* | RBC | Scotia | Scotia | Scotia | *Scotia* | *Scotia* | Scotia | TD | TD | TD | *TD* | *TD* | TD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | RBC | | | | | | Scotia | | | | | | TD | | | | | |
| | Current | | | | | | Current | | | | | | Current | | | | | |
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | 01-Dec-48 | 1-Jun-37 | 1-Jun-33 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | 30-Nov-44 | 31-May-33 | 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.50% | 0.75% |
| Benchmark Yield | 2.31% | 2.44% | 2.21% | 2.16% | 2.01% | 1.92% | 2.43% | 2.41% | 2.39% | 2.33% | 2.17% | 2.04% | 2.45% | 2.44% | 2.38% | 2.35% | 2.21% | 2.05% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 2.9 | 2.4 | 0.6 | 1.1 | 0.0 | 0.6 | (0.1) | 1.4 | 1.4 | 1.3 | 0.0 | 0.6 | 2.5 | 1.6 | 0.0 | 1.6 |
| Spread to GoC Curve (bp) | 106 | 107 | 106 | 96.00 | 74 | 56 | 117 | 107 | 99 | 92 | 70 | 55 | 115 | 107 | 97 | 90 | 60 | 45 |
| Re-Offered Yield | 3.37% | 3.52% | 3.30% | 3.14% | 2.76% | 2.50% | 3.60% | 3.49% | 3.38% | 3.26% | 2.89% | 2.61% | 3.60% | 3.52% | 3.38% | 3.26% | 2.81% | 2.52% |
| Commission (bp) | 2.7 | 3.9 | 3.8 | 4.7 | 7.6 | 8.7 | 2.4 | 3.7 | 3.6 | 4.5 | 7.7 | 8.6 | 2.4 | 3.2 | 3.6 | 4.5 | 7.4 | 8.7 |
| **All-in Yield** | **3.39%** | **3.56%** | **3.34%** | **3.19%** | **2.84%** | **2.58%** | **3.62%** | **3.53%** | **3.41%** | **3.31%** | **2.96%** | **2.69%** | **3.62%** | **3.55%** | **3.41%** | **3.31%** | **2.88%** | **2.61%** |
| **All-in Spread to GoC Curve (bp)** | **108.67** | **110.87** | **109.84** | **100.70** | **81.56** | **64.71** | **119.36** | **110.74** | **102.60** | **96.52** | **77.68** | **63.65** | **117.40** | **110.20** | **100.60** | **94.50** | **67.40** | **53.70** |

| Primary Comparable (S&P/Moody's/ DBRS) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| Province of Ontario (AA- / Aa2 / AA(L)) | 81 | 75 | 81 | 71 | 49 | 31 | 78 | 78 | 77 | 67 | 45 | 28 | 78 | 78 | 73 | 68 | 45 | 29 |

| Other Comparables (S&P/Moody's/ DBRS) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| Canada Mortgage & Housing Corp (AAA/Aaa/AAA) | n/a | n/a | n/a | 41 | 33 | 18 | | | | | | | | | | | | |
| City of Toronto (AA/Aa1/AA) | 103 | 97 | 100 | 88 | 65 | 46 | | | | | | | | | | | | |
| Hydro One Inc. (A(H)/A3/A) | 142 | n/a | n/a | 98 | 66 | 56 | | | | | | | 134 | 124 | 100 | 92 | 72 | 58 |
| Ontario Power Generation Inc. (A(low)/-/BBB+) | 162 | n/a | n/a | 120 | 89 | 77 | 165 | 0 | 0 | 120 | 95 | 81 | | | | | | |
| Toronto Hydro Corporation (A/-/A) | 135 | n/a | n/a | 95 | 62 | 52 | | | | | | | | | | | | |
| Canadian National Railway Co (A/A2/A) | 135 | n/a | n/a | 95 | 71 | 62 | | | | | | | | | | | | |
| Greater Toronto Airports Authority (A(high)/Aa3/A+) | 102 | n/a | n/a | 81 | 61 | 51 | | | | | | | | | | | | |
| NAV Canada (AA(low)/Aa2/AA-) | 101 | n/a | n/a | 81 | 61 | 51 | | | | | | | | | | | | |
| OPB Finance Trust (AA+/-/AA(H)) | | | | | | | | | | | | | 107 | 97 | 92 | 88 | 65 | 44 |
| Covered Bond - Bank (AAA/Aaa/AAA) | | | | | | | | | | | | | N/A | N/A | N/A | 85 | 66 | 53 |
| Schedule I Bank deposit notes (A1-Aa2 ; A-AA- ; AA) | | | | | | | | | | | | | | | | | | |
| Schedule I Bank covered bonds (Aaa ; AAA ; AAA) | | | | | | | | | | | | | | | | | | |
| Schedule I Bank ABS (Aaa ; AAA ; AAA) | | | | | | | | | | | | | | | | | | |
| ABS - Eagle 2017-1 A (AAA) | | | | | | | | | | | | | | | | | | |
| ABS - BMO Fortified (HELOC ABS) (AAA/AAA) | | | | | | | | | | | | | | | | | | |
| MBS - BAML NHA MBS (AAA/AAA) | | | | | | | | | | | | | | | | | | |
| CMBs: (AAA/Aaa/AAA) | | | | | | | | | | | | | | | | | | |
| PSP Investments (AAA/Aaa/AAA) | | | | | | | | | | | | | | | | | | |
| CPP Investment Board (AAA/Aaa/AAA) | | | | | | | 82 | 0 | 0 | 72 | 49 | 32 | | | | | | |
| BMO (Senior) (A+/A1/AA) | | | | | | | | | | | | | | | | | | |
| Nova Scotia Power (BBB+ / - / A(l)) | | | | | | | | | | | | | | | | | | |
| FortisAlberta (A- / Baa1 / A(l)) | | | | | | | | | | | | | | | | | | |
| Brookfield Renewable Energy Partners (BBB / - / BBB(H)) | | | | | | | | | | | | | | | | | | |
| Bruce Power (BBB / Baa2 / BBB) | | | | | | | | | | | | | | | | | | |
| City of Toronto (- / Aa1 / AA) | | | | | | | | | | | | | | | | | | |
| BNS - Denior Deposit Notes | | | | | | | 132 | 0 | 0 | 102 | 86 | 76 | | | | | | |
| Golden Credit Card Trust | | | | | | | 0 | 0 | 0 | 99 | 83 | 72 | | | | | | |
| Master Credit Card Trust | | | | | | | 0 | 0 | 0 | 99 | 83 | 72 | | | | | | |
| AAA CMBS (USD Swaps) | | | | | | | | | | | | | | | | | | |
| AAA Taxable Municipal Bonds (US Treasuries) | | | | | | | | | | | | | | | | | | |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 01-Jun-37 | 01-Jun-29 | 01-Jun-27 | 01-Mar-23 | 01-Mar-21 | 01-Dec-48 | 01-Jun-37 | 01-Jun-33 | 01-Jun-27 | 01-Mar-23 | 01-Mar-21 | 30-Nov-44 | 31-May-33 | 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.50% | 0.75% |
| Benchmark Yield | 2.31% | 2.44% | 2.21% | 2.16% | 2.01% | 1.92% | 2.43% | 2.41% | 2.39% | 2.33% | 2.17% | 2.04% | 2.45% | 2.44% | 2.38% | 2.35% | 2.21% | 2.05% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 2.9 | 2.4 | 0.6 | 1.1 | 0.0 | 0.6 | (0.1) | 1.4 | 1.4 | 1.3 | 0.0 | 0.6 | 2.5 | 1.6 | 0.0 | 1.6 |
| Spread to GoC Curve (bp) | 138 | 137 | 138 | 128 | 106 | 88 | 152 | 142 | 129 | 122 | 100 | 85 | 145 | 137 | 127 | 120 | 90 | 75 |
| Re-Offered Yield | 3.69% | 3.82% | 3.62% | 3.46% | 3.08% | 2.82% | 3.95% | 3.84% | 3.68% | 3.56% | 3.19% | 2.91% | 3.90% | 3.82% | 3.68% | 3.56% | 3.11% | 2.82% |
| Commission (bp) | 2.8 | 0.0 | 3.9 | 4.8 | 7.6 | 8.8 | 2.4 | 3.7 | 3.6 | 4.5 | 7.7 | 8.6 | 2.4 | 3.2 | 3.6 | 4.5 | 7.4 | 8.7 |
| **All-in Yield** | **3.71%** | **3.82%** | **3.66%** | **3.51%** | **3.16%** | **2.90%** | **3.97%** | **3.88%** | **3.71%** | **3.61%** | **3.26%** | **2.99%** | **3.92%** | **3.85%** | **3.71%** | **3.61%** | **3.18%** | **2.91%** |
| **All-in Spread to GoC Curve (bp)** | **140.78** | **137.00** | **141.92** | **132.78** | **113.62** | **96.76** | **154.36** | **145.74** | **132.60** | **126.52** | **107.68** | **93.65** | **147.40** | **140.20** | **130.60** | **124.50** | **97.40** | **83.70** |

| Other Comparables (S&P/Moody's/ DBRS) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| RBC Sr-Sub. | n/a | n/a | n/a | 83 | 63 | n/a | | | | | | | | | | | | |
| Highway 407 (A, A) | | | | | | | | | | | | | | | | | | |
| NAV Canada (AA-, AA low) | | | | | | | | | | | | | | | | | | |
| GTAA (Aa3, A+) | | | | | | | | | | | | | | | | | | |
| Hydro One (A3/A/A high) | | | | | | | | | | | | | | | | | | |
| ABS - BMO Fortified (HELOC ABS) (AA/AA) | | | | | | | | | | | | | | | | | | |
| ABS - Ford Floorplan Auto Securitization (AA / AA / AA) | | | | | | | | | | | | | | | | | | |
| BMO (Senior) (A+/A1/AA) | | | | | | | | | | | | | | | | | | |
| Nav Canada (sub) (AA-/Aa2/AAL) | | | | | | | | | | | | | | | | | | |
| City of Toronto (AA / Aa1 / AA) | | | | | | | | | | | | | | | | | | |
| Bank ABS (AAA / - / AAA) | | | | | | | | | | | | | | | | | | |
| Auto ABS (Ford) (AAA / Aaa / AAA) | | | | | | | | | | | | | | | | | | |
| NHA MBS (AAA / Aaa / AAA) | | | | | | | | | | | | | | | | | | |
| AA CMBS (USD Swaps) | | | | | | | | | | | | | | | | | | |
| AA Taxable Municipal Bonds (US Treasuries) | | | | | | | | | | | | | | | | | | |

| Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | 01-Dec-48 | 1-Jun-37 | 1-Jun-33 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | 30-Nov-44 | 31-May-33 | 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.75% | 0.75% | 2.75% | 5.00% | 5.75% | 1.00% | 1.50% | 0.75% |
| Benchmark Yield | 2.31% | 2.44% | 2.21% | 2.16% | 2.01% | 1.92% | 2.43% | 2.41% | 2.39% | 2.33% | 2.18% | 2.04% | 2.45% | 2.44% | 2.38% | 2.35% | 2.21% | 2.05% |
| Curve Adjustment (bp) | 0.0 | 0.6 | 2.9 | 2.4 | 0.6 | 1.1 | 0.0 | 0.6 | (0.1) | 1.4 | 1.4 | 1.3 | 0.0 | 0.6 | 2.5 | 1.6 | 0.0 | 1.6 |
| Spread to GoC Curve (bp) | 174 | 171 | 174 | 164 | 142 | 124 | 190 | 180 | 159 | 152 | 130 | 115 | 175 | 167 | 157 | 150 | 120 | 105 |
| Re-Offered Yield | 4.05% | 4.16% | 3.98% | 3.82% | 3.44% | 3.18% | 4.33% | 4.22% | 3.98% | 3.86% | 3.49% | 3.21% | 4.20% | 4.12% | 3.98% | 3.86% | 3.41% | 3.12% |
| Commission (bp) | 2.9 | 0.0 | 4.0 | 4.9 | 7.7 | 8.8 | 2.4 | 3.7 | 3.6 | 4.5 | 7.7 | 8.6 | 2.4 | 3.2 | 3.6 | 4.5 | 7.4 | 8.7 |
| **All-in Yield** | **4.08%** | **4.16%** | **4.02%** | **3.87%** | **3.52%** | **3.26%** | **4.35%** | **4.26%** | **4.01%** | **3.91%** | **3.57%** | **3.29%** | **4.22%** | **4.15%** | **4.01%** | **3.91%** | **3.48%** | **3.21%** |
| **All-in Spread to GoC Curve (bp)** | **176.90** | **171.00** | **178.02** | **168.86** | **149.69** | **132.82** | **192.36** | **183.74** | **162.60** | **156.52** | **137.68** | **123.65** | **177.40** | **170.20** | **160.60** | **154.50** | **127.40** | **113.70** |

| Other Comparables (S&P/Moody's/ DBRS) | RBC | | | | | | Scotia | | | | | | TD | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year | 3-year |
| **Ontario Power Generation (BBB+/A low)** | | | | | | | | | | | | | | | | | | |
| **Highway 407 (A, A)** | | | | | | | | | | | | | | | | | | |
| **Enbridge Gas Distribution (A-, A)** | | | | | | | | | | | | | | | | | | |
| **Hydro One (A3/A/A high)** | | | | | | | | | | | | | | | | | | |
| **Schedule 1 Bank ABS (A)** | | | | | | | | | | | | | | | | | | |
| ABS - Eagle 2017-1 Sub A Rated Tranche | | | | | | | | | | | | | | | | | | |
| ABS - BMO Fortified Sub A Rated Tranche | | | | | | | | | | | | | | | | | | |
| Hydro One (A/A3/AH) | | | | | | | | | | | | | | | | | | |
| OPG (BBB+/-/AL) | | | | | | | | | | | | | | | | | | |
| 10-year A CMBS (USD Swaps) | | | | | | | | | | | | | | | | | | |

| | | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A Taxable Municipal Bonds (US Treasuries) | | | | | | | | | | | | | | | | | | |
| | | | 32.00<br>68 | | | | | 30.00<br>60 | | | | | 30.00<br>60 | | | | | |

| | Fair Hydro Spread to Ontarios | | |
|---|---|---|---|
| | 5 Year | 10 Year | 15 Year |
| **5-Feb-18** | 18.3 | 21.8 | 23.9 |
| **8-Feb-18** | 19.3 | 22.4 | 24.6 |
| **12-Feb-18** | 19.3 | 22.7 | 24.8 |
| **20-Feb-18** | 19.9 | 20.0 | 24.0 |
| **26-Feb-18** | 19.6 | 16.9 | 23.2 |
| **5-Mar-18** | 20.8 | 19.4 | 23.2 |
| **12-Mar-18** | 21.7 | 21.6 | 23.7 |
| **19-Mar-18** | 23.0 | 23.9 | 27.5 |
| **26-Mar-18** | 22.9 | 23.5 | 26.6 |
| **3-Apr-18** | 21.9 | 20.0 | 24.3 |
| **9-Apr-18** | 18.3 | 18.0 | 22.6 |
| **19-Apr-18** | 21.3 | 21.0 | 24.8 |

| 20 Year | 30 Year | Fair Hydro Spread to GOC 5 Year | 10 Year | 15 Year | 20 Year |
|---|---|---|---|---|---|
| 27.2 | 29.7 | 56.8 | 80.6 | 91.2 | |
| 28.3 | 30.8 | 59.3 | 81.4 | 92.0 | |
| 29.1 | 31.4 | 61.0 | 83.7 | 94.5 | |
| 28.8 | 32.6 | 59.8 | 82.1 | 94.1 | |
| 28.6 | 31.9 | 59.4 | 82.1 | 94.0 | |
| 27.8 | 30.8 | 63.4 | 84.9 | 96.7 | |
| 28.9 | 32.2 | 63.8 | 85.3 | 97.0 | |
| 32.6 | 35.7 | 63.7 | 86.6 | 97.4 | |
| 31.1 | 35.0 | 65.8 | 88.6 | 99.4 | |
| 29.8 | 32.8 | 68.0 | 90.6 | 102.5 | |
| 28.0 | 31.2 | 68.4 | 90.7 | 103.0 | |
| 30.7 | 35.4 | 66.5 | 88.0 | 100.1 | 107.0 |

| | Ontario Spread to GOC | | | | |
|---|---|---|---|---|---|
| **30 Year** | **5 Year** | **10 Year** | **15 Year** | **20 Year** | **30 Year** |
| 99.1 | 38.5 | 58.8 | 67.3 | | 69.4 |
| 100.4 | 40.1 | 59.0 | 67.4 | | 69.7 |
| 103.6 | 41.7 | 61.0 | 69.7 | | 72.2 |
| 104.8 | 39.8 | 62.0 | 70.4 | | 72.2 |
| 104.6 | 39.8 | 65.1 | 70.8 | | 72.7 |
| 107.1 | 42.7 | 65.5 | 73.5 | | 76.3 |
| 107.9 | 42.2 | 63.7 | 73.3 | | 75.8 |
| 108.6 | 40.7 | 62.7 | 69.9 | | 72.9 |
| 110.6 | 42.8 | 65.0 | 72.8 | | 75.5 |
| 113.0 | 46.1 | 70.6 | 78.2 | | 80.2 |
| 113.4 | 50.1 | 72.8 | 80.4 | | 82.3 |
| 112.6 | 45.3 | 67.0 | 75.3 | 76.3 | 77.3 |

| | Fair Hydro Spread to Ontarios | | |
|---|---|---|---|
| | 5 Year | 10 Year | 15 Year |
| **5-Feb-18** | 39.7 | 44.0 | 47.7 |
| **8-Feb-18** | 45.3 | 49.2 | 53.0 |
| **12-Feb-18** | 46.2 | 50.3 | 54.2 |
| **20-Feb-18** | 46.8 | 48.0 | 53.2 |
| **26-Feb-18** | 46.4 | 44.9 | 52.6 |
| **5-Mar-18** | 47.6 | 47.4 | 52.6 |
| **12-Mar-18** | 48.7 | 49.6 | 53.1 |
| **19-Mar-18** | 50.0 | 51.9 | 57.0 |
| **26-Mar-18** | 50.3 | 51.8 | 56.3 |
| **3-Apr-18** | 49.3 | 48.4 | 54.2 |
| **9-Apr-18** | 45.5 | 46.2 | 53.2 |
| **19-Apr-18** | 48.8 | 50.3 | 55.5 |

| 20 Year | 30 Year | Fair Hydro Spread to GOC 5 Year | 10 Year | 15 Year | 20 Year |
|---|---|---|---|---|---|
| 51.8 | 54.7 | 78.2 | 102.8 | 115.0 | |
| 57.6 | 60.3 | 85.4 | 108.2 | 120.4 | |
| 59.3 | 61.9 | 87.8 | 111.3 | 123.9 | |
| 58.9 | 63.0 | 86.6 | 110.1 | 123.6 | |
| 58.8 | 62.4 | 86.3 | 110.1 | 123.4 | |
| 57.9 | 61.2 | 90.3 | 112.9 | 126.1 | |
| 59.0 | 62.6 | 90.8 | 113.3 | 126.4 | |
| 62.7 | 66.1 | 90.7 | 114.6 | 126.8 | |
| 61.2 | 65.7 | 93.1 | 116.8 | 129.1 | |
| 60.5 | 63.8 | 95.3 | 119.0 | 132.3 | |
| 58.5 | 62.3 | 95.6 | 119.0 | 132.7 | |
| 62.2 | 67.3 | 94.0 | 117.3 | 130.9 | 138.6 |

| 30 Year | Ontario Spread to GOC 5 Year | 10 Year | 15 Year | 20 Year | 30 Year |
|---|---|---|---|---|---|
| 124.1 | 38.5 | 58.8 | 67.3 | | 69.4 |
| 130.0 | 40.1 | 59.0 | 67.4 | | 69.7 |
| 134.1 | 41.7 | 61.0 | 69.7 | | 72.2 |
| 135.2 | 39.8 | 62.0 | 70.4 | | 72.2 |
| 135.1 | 39.8 | 65.1 | 70.8 | | 72.7 |
| 137.6 | 42.7 | 65.5 | 73.5 | | 76.3 |
| 138.3 | 42.2 | 63.7 | 73.3 | | 75.8 |
| 139.0 | 40.7 | 62.7 | 69.9 | | 72.9 |
| 141.3 | 42.8 | 65.0 | 72.8 | | 75.5 |
| 144.0 | 46.1 | 70.6 | 78.2 | | 80.2 |
| 144.3 | 50.1 | 72.8 | 79.5 | | 81.9 |
| 144.5 | 45.3 | 67.0 | 75.3 | 76.3 | 77.3 |

| | Fair Hydro Spread to Ontarios | | |
|---|---|---|---|
| | 5 Year | 10 Year | 15 Year |
| **5-Feb-18** | 60.8 | 66.8 | 73.7 |
| **8-Feb-18** | 72.6 | 78.3 | 86.1 |
| **12-Feb-18** | 76.0 | 81.8 | 93.2 |
| **20-Feb-18** | 76.4 | 83.6 | 92.2 |
| **26-Feb-18** | 76.1 | 80.5 | 91.6 |
| **5-Mar-18** | 77.3 | 83.0 | 91.6 |
| **12-Mar-18** | 78.3 | 85.2 | 92.1 |
| **19-Mar-18** | 79.7 | 87.5 | 96.0 |
| **26-Mar-18** | 80.3 | 87.7 | 95.6 |
| **3-Apr-18** | 79.9 | 84.7 | 93.9 |
| **9-Apr-18** | 76.2 | 82.5 | 92.9 |
| **19-Apr-18** | 79.8 | 86.9 | 95.5 |

| 20 Year | 30 Year | Fair Hydro Spread to GOC 5 Year | 10 Year | 15 Year | 20 Year |
|---|---|---|---|---|---|
| 80.4 | 84.5 | 99.3 | 125.6 | 141.0 | |
| 92.5 | 96.8 | 112.7 | 137.3 | 153.5 | |
| 96.6 | 101.5 | 117.7 | 142.8 | 162.9 | |
| 99.5 | 104.0 | 116.3 | 145.6 | 162.6 | |
| 98.5 | 103.4 | 115.9 | 145.6 | 162.4 | |
| 97.9 | 102.2 | 119.9 | 148.5 | 165.1 | |
| 99.2 | 103.6 | 120.5 | 148.9 | 165.4 | |
| 102.3 | 107.1 | 120.3 | 150.1 | 165.8 | |
| 101.0 | 107.0 | 123.1 | 152.7 | 168.4 | |
| 100.9 | 105.3 | 126.0 | 155.3 | 172.1 | |
| 99.4 | 103.8 | 126.3 | 155.3 | 172.4 | |
| 103.7 | 109.4 | 125.0 | 153.9 | 170.9 | 180.0 |

| 30 Year | Ontario Spread to GOC 5 Year | 10 Year | 15 Year | 20 year | 30 Year |
|---|---|---|---|---|---|
| 153.9 | 38.5 | 58.8 | 67.3 | | 69.4 |
| 166.5 | 40.1 | 59.0 | 67.4 | | 69.7 |
| 173.7 | 41.7 | 61.0 | 69.7 | | 72.2 |
| 176.2 | 39.8 | 62.0 | 70.4 | | 72.2 |
| 176.1 | 39.8 | 65.1 | 70.8 | | 72.7 |
| 178.6 | 42.7 | 65.5 | 73.5 | | 76.3 |
| 179.3 | 42.2 | 63.7 | 73.3 | | 75.8 |
| 180.0 | 40.7 | 62.7 | 69.9 | | 72.9 |
| 182.6 | 42.8 | 65.0 | 72.8 | | 75.5 |
| 185.4 | 46.1 | 70.6 | 78.2 | | 80.2 |
| 185.7 | 50.1 | 72.8 | 79.5 | | 81.9 |
| 186.6 | 45.3 | 67.0 | 75.3 | 76.3 | 77.3 |

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | Current | |
|---|---|---|
| | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| **Spread to GoC Curve (bp)** | **108** | **107** |
| Re-Offered Yield | 3.51% | 3.49% |
| Commission (bp) | 2.7 | 3.4 |
| **All-in Yield** | **3.54%** | **3.52%** |

| Primary Comparable (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| ONTARIO: (A+/Aa2/AAL) | 75 | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| ABS - Eagle 2017-1 A (AAA) | | |
| ABS - BMO Fortified (HELOC ABS) (AAA/AAA) | | |
| MBS - BAML NHA MBS (AAA/AAA) | | |
| CMBs: (AAA/Aaa/AAA) | | |
| PSP Investments (AAA/Aaa/AAA) | | |
| CPP Investment Board (AAA/Aaa/AAA) | 91 | |
| BMO (Senior) (A+/A1/AA) | 122 | |
| Nav Canada (sub) (AA-/Aa2/AAL) | 99 | |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | Current | |
|---|---|---|
| | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 01-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| **Spread to GoC Curve (bp)** | **147** | **146** |
| Re-Offered Yield | 3.90% | 3.88% |
| Commission (bp) | 2.8 | 3.5 |
| **All-in Yield** | **3.93%** | **3.92%** |

| Primary Comparable (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| Province of Ontario (AA- / Aa2 / AA(L)) | 75 | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| ABS - BMO Fortified (HELOC ABS) (AA/AA) | | |
| ABS - Ford Floorplan Auto Securitization (AA / AA / AA) | | |
| BMO (Senior) (A+/A1/AA) | 122 | |
| Nav Canada (sub) (AA-/Aa2/AAL) | 99 | |
| City of Toronto (AA / Aa1 / AA) | 96 | 95 |

| Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2) | Current | |
|---|---|---|
| | 30-year | 20-year |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.42% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| **Spread to GoC Curve (bp)** | **221** | **217** |
| Re-Offered Yield | 4.64% | 4.59% |
| Commission (bp) | 2.9 | 3.7 |
| **All-in Yield** | **4.67%** | **4.63%** |

| Primary Comparable (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| Province of Ontario (AA- / Aa2 / AA(L)) | 75 | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | Current | |
|---|---|---|
| Spread to GoC Curve (bp) | 30-year | 20-year |
| ABS - Eagle 2017-1 Sub A Rated Tranche | | |
| ABS - BMO Fortified Sub A Rated Tranche | | |
| Hydro One (A/A3/AH) | 137 | |
| OPG (BBB+/-/AL) | 166 | |

| | | |
|---|---|---|
| Generic Corporate Credit Spreads AA | 101 | |
| Generic Corporate Credit Spreads A | 159 | |
| Generic Corporate Credit Spreads BBB | 233 | |

* Generic Corporate Credit Spreads derived from an average of all Corporate Bonds included

| Bank Nam |
|---|
| Date |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 1-Jun-29 | 1-Jun-27 | 01-Sep-22 | 01-Sep-20 | | | | | |
| 5.75% | 1.00% | 2.75% | 0.75% | | | | | |
| 2.37% | 2.33% | 2.18% | 1.99% | 10bps | 11bps | 13bps | 15bps | 14bps |
| 1.9 | 1.7 | 1.5 | 6.9 | 0bps | 0bps | -1bps | -1bps | 1bps |
| **100** | **90** | **66** | **50** | 1bps | 1bps | -2bps | -1bps | -1bps |
| 3.39% | 3.25% | 2.85% | 2.56% | 11bps | 12bps | 10bps | 13bps | 13bps |
| 3.4 | 4.6 | 7.5 | 6.9 | | | | | |
| **3.43%** | **3.30%** | **2.92%** | **2.63%** | 11bps | 12bps | 10bps | 13bps | 13bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 73 | 65 | 43 | 28 | -7bps | -7bps | -7bps | -7bps | -7bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| | | 88 | | | | | | -1bps |
| | | 82 | 67 | | | | | -1bps |
| | | 67 | 52 | | | | | -1bps |
| 41 | 36 | 29 | 17 | | | -5bps | -5bps | -3bps |
| | 71 | 48 | 32 | | | | -3bps | -3bps |
| | 71 | 48 | 32 | -3bps | | | -3bps | -3bps |
| | 97 | 82 | 70 | -1bps | | | -1bps | 1bps |
| | 82 | 57 | 52 | -5bps | | | -5bps | -5bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 01-Jun-29 | 01-Jun-27 | 01-Sep-22 | 01-Sep-20 | | | | | |
| 5.75% | 1.00% | 2.75% | 0.75% | | | | | |
| 2.37% | 2.33% | 2.18% | 1.99% | 10bps | 11bps | 13bps | 15bps | 14bps |
| 1.9 | 1.7 | 1.5 | 6.9 | 0bps | 0bps | -1bps | -1bps | 1bps |
| **138** | **119** | **91** | **75** | 1bps | 1bps | -2bps | -1bps | -1bps |
| 3.77% | 3.54% | 3.10% | 2.81% | 11bps | 12bps | 10bps | 13bps | 13bps |
| 3.5 | 4.7 | 7.5 | 6.9 | | | | | |
| **3.81%** | **3.59%** | **3.17%** | **2.88%** | 11bps | 12bps | 10bps | 13bps | 13bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 73 | 65 | 43 | 28 | -7bps | -7bps | -7bps | -7bps | -7bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| | | | 87 | | | | | |
| | | | 102 | | | | | |
| | 97 | 82 | 70 | -1bps | | | -1bps | 1bps |
| | 82 | 57 | 52 | -5bps | | | -5bps | -5bps |
| 93 | 82 | 58.5 | 41.5 | -7bps | -7bps | -7bps | -7bps | -7bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-29 | 1-Jun-27 | 01-Sep-22 | 01-Sep-20 | | | | | |
| 5.75% | 1.00% | 2.75% | 0.75% | | | | | |
| 2.37% | 2.33% | 2.18% | 1.99% | 10bps | 11bps | 13bps | 15bps | 14bps |
| 1.9 | 1.7 | 1.5 | 6.9 | 0bps | 0bps | -1bps | -1bps | 1bps |
| **205** | **169** | **135** | **120** | 1bps | -1bps | -2bps | -1bps | -1bps |
| 4.44% | 4.04% | 3.54% | 3.26% | 11bps | 10bps | 10bps | 13bps | 13bps |
| 3.5 | 4.8 | 7.6 | 6.9 | | | | | |
| **4.48%** | **4.09%** | **3.62%** | **3.33%** | 11bps | 10bps | 10bps | 13bps | 13bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 73 | 65 | 43 | 28 | -7bps | -7bps | -7bps | -7bps | -7bps |

| | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| | | 153 | | | | | | -1bps |
| | | 135 | | | | | | -1bps |
| | 100 | 75 | 62 | -5bps | | | -5bps | -5bps |
| | 119 | 94 | 81 | -6bps | | | -6bps | -6bps |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 91 | 70 | | -4bps | | | -2bps | -2bps |
| | 119 | 88 | | -4bps | | | -3bps | -2bps |
| | 177 | 123 | | -4bps | | | -4bps | -4bps |

in BMO Corporate Bond Universe Pricing

| Bank of Montreal |
| --- |
| 19-Apr-18 |

| |
| --- |
| **3-year** |
| 10bps<br>1bps<br>-2bps<br>9bps |
| 9bps |

| |
| --- |
| **3-year** |
| -4bps |

| |
| --- |
| **3-year** |
| -2bps<br>-2bps<br>-1bps<br>0bps<br>0bps<br>-2bps<br>-3bps |

| |
| --- |
| **3-year** |
| 10bps<br>1bps<br>-2bps<br>9bps |
| 9bps |

| |
| --- |
| **3-year** |
| -4bps |

| 3-year |
| --- |
| -2bps |
| -2bps |
| -2bps |
| -3bps |
| -4bps |

| 3-year |
| --- |
| 10bps |
| 1bps |
| -2bps |
| 9bps |
| 9bps |

| 3-year |
| --- |
| -4bps |

| 3-year |
| --- |
| -3bps |
| -4bps |

| |
| --- |

**Note: All ratings are to be confirmed**

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | 30-year |
|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.43% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | **111** |
| Re-Offered Yield | 3.53% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **3.56%** |

| Primary Comparable (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(l)) | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| OPG (BBB+ / - / A(l)) | 167 |
| Toronto Hydro (A / - / A) | 132 |
| Nova Scotia Power (BBB+ / - / A(l)) | 150 |
| FortisAlberta (A- / Baa1 / A(l)) | 138 |
| Brookfield Renewable Energy Partners (BBB / - / BBB(H)) | 245 |
| Bruce Power (BBB / Baa2 / BBB) | 212 |
| City of Toronto (- / Aa1 / AA) | 100 |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | 30-year |
|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.43% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | **138** |
| Re-Offered Yield | 3.80% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **3.83%** |

| Primary Comparable (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(l)) | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Bank ABS (AAA / - / AAA) | -- |
| Auto ABS (Ford) (AAA / Aaa / AAA) | -- |
| NHA MBS (AAA / Aaa / AAA) | -- |

| **Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2)** | **30-year** |
|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.43% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | **165** |
| Re-Offered Yield | 4.07% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **4.10%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(l)) | 75 |

| Other Comparables (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |

| Bank Nam | CIBC |
|---|---|
| Date | 4/19/2018 |

| Bank Nam | |
|---|---|
| Date | |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 01-Jun-37 | 01-Jun-33 | 01-Jun-28 | 01-Jun-25 | 01-Mar-23 | - | - | - | - | - |
| 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | - | - | - | - | - |
| 2.444% | 2.37% | 2.32% | 2.26% | 2.15% | 0.05% | 0.06% | 0.08% | 0.10% | 0.11% |
| 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0.0 | (0.1) | 0.1 | 0.1 | 0.1 |
| **107** | **99** | **81** | **62** | **48** | -6 | -7 | -6 | -8 | -5 |
| 3.52% | 3.36% | 3.13% | 2.88% | 2.65% | 0.00% | -0.01% | 0.02% | 0.03% | 0.06% |
| 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | - | - | - | - | - |
| **3.55%** | **3.38%** | **3.15%** | **2.90%** | **2.66%** | **0.00%** | **-0.01%** | **0.02%** | **0.03%** | **0.06%** |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 75 | 73 | 65 | 46 | 28 | -6 | -6 | -6 | -8 | -5 |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| -- | -- | 120 | 80 | 64 | (8) | -- | -- | (5) | (3) |
| -- | -- | 96 | 69 | 57 | (4) | -- | -- | 0 | 0 |
| -- | -- | 107 | 78 | 63 | (3) | -- | -- | 0 | 0 |
| -- | -- | 98 | 70 | -- | (2) | -- | -- | 0 | (1) |
| -- | -- | 180 | 127 | 105 | (2) | -- | -- | (5) | (3) |
| -- | -- | 152 | 114 | -- | (8) | -- | -- | (8) | 0 |
| 101 | -- | 81.5 | -- | -- | (6) | (5) | -- | (6) | -- |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 01-Jun-37 | 01-Jun-33 | 01-Jun-28 | 01-Jun-25 | 01-Mar-23 | - | - | - | - | - |
| 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | - | - | - | - | - |
| 2.444% | 2.37% | 2.32% | 2.26% | 2.15% | 0.05% | 0.06% | 0.08% | 0.10% | 0.11% |
| 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0 | (0) | 0 | 0 | 0 |
| **134** | **126** | **108** | **89** | **75** | (6) | (7) | (6) | (8) | (5) |
| 3.79% | 3.63% | 3.40% | 3.15% | 2.92% | 0.00% | -0.01% | 0.02% | 0.03% | 0.06% |
| 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | 0.00% | 0.00% | 0.00% | 0.00% | 0.00% |
| **3.82%** | **3.65%** | **3.42%** | **3.17%** | **2.93%** | **0.00%** | **-0.01%** | **0.02%** | **0.03%** | **0.06%** |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 75 | 73 | 65 | 46 | 28 | (6) | (6) | (6) | (8) | (5) |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| -- | -- | -- | 82 | 68 | -- | -- | -- | -- | -1 |
| -- | -- | -- | 91 | 78 | -- | -- | -- | -- | -1 |
| -- | -- | -- | 48 | 37 | -- | -- | -- | -- | 0 |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-33 | 1-Jun-28 | 01-Jun-25 | 01-Mar-23 | - | - | - | - | - |
| 5.00% | 5.75% | 2.00% | 2.25% | 1.75% | - | - | - | - | - |
| 2.444% | 2.37% | 2.32% | 2.26% | 2.15% | 0.05% | 0.06% | 0.08% | 0.10% | 0.11% |
| 0.6 | (0.1) | (0.2) | (0.3) | 1.5 | 0 | (0) | 0 | 0 | 0 |
| **161** | **153** | **135** | **116** | **102** | (6) | (7) | (6) | (8) | (5) |
| 4.06% | 3.90% | 3.67% | 3.42% | 3.19% | 0.00% | -0.01% | 0.02% | 0.03% | 0.06% |
| 2.7 | 2.4 | 2.1 | 1.8 | 1.2 | - | - | - | - | - |
| **4.09%** | **3.92%** | **3.69%** | **3.44%** | **3.20%** | **0.00%** | **-0.01%** | **0.02%** | **0.03%** | **0.06%** |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 75 | 73 | 65 | 46 | 28 | (6) | (6) | (6) | (8) | (5) |

| Current | | | | | Week over Week | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |

| CIBC |
| --- |
| 4/16/2018 |

| | |
| --- | --- |
| | **3-year** |
| Beginning Balance | - |
| Increases due to Purchases | - |
| Increases due to Accretion | 0.10% |
| Decreases due to Sales | 0.5 |
| Decreases due to Paydowns | -3 |
| Decreases due to Credit Impairment | 0.08% |
| Net Transfers In or Out of Level 3 | - |
| Ending Balance | **0.08%** |

| | |
| --- | --- |
| | **3-year** |
| Net Realized Gains (Losses) | -3 |

| | |
| --- | --- |
| | **3-year** |
| Beginning Balance | (3) |
| Increases due to Purchases | 0 |
| Increases due to Accretion | 0 |
| Decreases due to Sales | -- |
| Decreases due to Paydowns | (2) |
| Decreases due to Credit Impairment | -- |
| Net Transfers In or Out of Level 3 | -- |

| | |
| --- | --- |
| | **3-year** |
| Beginning Balance | - |
| Increases due to Purchases | - |
| Increases due to Accretion | 0.10% |
| Decreases due to Sales | 1 |
| Decreases due to Paydowns | (3) |
| Decreases due to Credit Impairment | 0.08% |
| Net Transfers In or Out of Level 3 | 0.00% |
| Ending Balance | **0.08%** |

| | |
| --- | --- |
| | **3-year** |
| Net Realized Gains (Losses) | (3) |

| 3-year |
| --- |
| -2 |
| -1 |
| 0 |

| 3-year |
| --- |
| - |
| - |
| 0.10% |
| 1 |
| (3) |
| 0.08% |
| - |
| **0.08%** |

| 3-year |
| --- |
| (3) |

| 3-year |
| --- |

| | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 1DEC48 | 1JUN37 and 1JUN41 |
| Benchmark Canada Bond Coupon | 2.750% | 5.000% |
| Benchmark Yield | 2.431% | 2.444% |
| Curve Adjustment (bp) | 0.000% | 0.006% |
| Spread to GoC Curve (bp) | **1.170%** | **1.070%** |
| Re-Offered Yield | 3.601% | 3.514% |
| Commission (bp) | 0.017% | 0.025% |
| **All-in Yield** | **3.62%** | **3.54%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(l)) | **0.7440%** | **0.74500%** |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to Relevant Benchmark (bp) | **30-year** | **20-year** |
| AAA CMBS (USD Swaps) | | |
| AAA Taxable Municipal Bonds (US Treasuries) | +95 AREA | -85 AREA (vs 30y U |

| **Indicative New Issue Spreads - Sub Notes (AA/Aa2)** | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 1DEC48 | 1JUN37 and 1JUN41 |
| Benchmark Canada Bond Coupon | 2.750% | 4.000% |
| Benchmark Yield | 2.431% | 2.444% |
| Curve Adjustment (bp) | 0.000% | 0.007% |
| Spread to GoC Curve (bp) | **1.520%** | **1.420%** |
| Re-Offered Yield | 3.951% | 3.864% |
| Commission (bp) | 0.017% | 0.025% |
| **All-in Yield** | **3.97%** | **3.89%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|

| Spread to GoC Curve (bp) | 30-year | 20-year |
|---|---|---|
| Province of Ontario (AA- / Aa2 / AA(l)) | **0.7440%** | **0.74500%** |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to Relevant Benchmark (bp) | **30-year** | **20-year** |
| AA CMBS (USD Swaps) | | |
| AA Taxable Municipal Bonds (US Treasuries) | +115 - 120 AREA | 00 AREA (vs 30y US |

| **ndicative New Issue Spreads - Jr. Sub Notes (A/Aa2** | **30-year** | **20-year** |
|---|---|---|
| Benchmark Canada Bond Maturity | 1DEC48 | 1JUN37 and 1JUN41 |
| Benchmark Canada Bond Coupon | 2.750% | 4.000% |
| Benchmark Yield | 2.431% | 2.444% |
| Curve Adjustment (bp) | 0.000% | 0.007% |
| Spread to GoC Curve (bp) | **2.120%** | **2.020%** |
| Re-Offered Yield | 4.551% | 4.464% |
| Commission (bp) | 0.017% | 0.025% |
| **All-in Yield** | **4.57%** | **4.49%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(l)) | **0.7440%** | **0.74500%** |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to Relevant Benchmark (bp) | **30-year** | **20-year** |
| 10-year A CMBS (USD Swaps) | | |
| A Taxable Municipal Bonds (US Treasuries) | +140 - 145 AREA | - 130 AREA (vs 30y |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | |
| 5.750% | 2.000% | | | |
| 2.390% | 2.312% | | | |
| 0.049% | 0.008% | | | |
| **0.9700%** | **0.770%** | | | |
| 3.360% | 3.082% | | | |
| 0.033% | 0.050% | | | |
| **3.39%** | **3.13%** | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| **0.70600%** | **0.66700%** | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| -110 AREA (vs 10y | 85 bps area +75-80 AREA | +65 - 70 AREA | +55 - 60 AREA | +0 bps |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | |
| 5.750% | 2.000% | | | |
| 2.390% | 2.312% | | | |
| 0.049% | 0.008% | | | |
| **1.32000%** | **1.120%** | | | |
| 3.710% | 3.432% | | | |
| 0.033% | 0.050% | | | |
| **3.71%** | **3.48%** | | | |

| Current | | | | |
|---|---|---|---|---|

| 15-year | 10-year | 5-year | 3-year | 30-year |
|---|---|---|---|---|
| **0.70600%** | **0.66700%** | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| - 130 AREA (vs 10y | 120 - 125 bps AREA<br>+100 - 105 AREA | +75 - 80 AREA | +60 - 65 AREA | +0 bps |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1JUN29 and 1JUN33 | 1JUN27 and 1JUN29 | | | |
| 5.750% | 2.000% | | | |
| 2.390% | 2.312% | | | |
| 0.049% | 0.008% | | | |
| **1.920%** | **1.720%** | | | |
| 4.310% | 4.032% | | | |
| 0.033% | 0.050% | | | |
| **4.31%** | **4.08%** | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| **0.70600%** | **0.66700%** | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| - 155 AREA (vs 10y | 160 -170 bps AREA<br>+120 - 125 AREA | +95 - 100 AREA | +85 - 90 AREA | +0 bps |

| Bank Name | GS |
|---|---|
| Date | 4/19/2018 |

| Week over Week | | | | |
|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year |
| | | | | |
| | | | | |

| Week over Week | | | | |
|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year |
| | | | | |

| Versus 4.17.19 Template | | | | |
|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year |
| +0 bps | +0 bps | +0 bps<br>+0 bps | +0 bps | +0 bps |

| Versus 4.17.19 Template | | | | |
|---|---|---|---|---|
| 20-year | 15-year | 10-year | 5-year | 3-year |
| | | | | |
| | | | | |

| Week over Week |
|---|

| 20-year | 15-year | 10-year | 5-year | 3-year |
|---|---|---|---|---|
| | | | | |

| Versus 4.17.19 Template | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| +0 bps | +0 bps | +0 bps<br>+0 bps | +0 bps | +0 bps |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |
| | | | | |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |

| Versus 4.17.19 Template | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| +0 bps | +0 bps | +0 bps<br>+0 bps | +0 bps | +0 bps |

**Fair Hydro Trust, Indicative Spreads from NBC**

**(Moodys, DBRS)**

| **Indicative New Issue Spreads - Senior Notes (Aa2/AAA)** | |
|---|---|
| | **30-year** |
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.40% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | 115 |
| Re-Offered Yield | 3.55% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **3.58%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| **Schedule I Bank deposit notes (A1-Aa2 ; A-AA- ; AA)** | 140 |
| **Schedule I Bank covered bonds (Aaa ; AAA ; AAA)** | 123 |
| **Schedule I Bank ABS (Aaa ; AAA ; AAA)** | 145 |
| **FHT Series 2018-1** | |

| **Indicative New Issue Spreads - Sub Notes (Aa2/AA)** | |
|---|---|
| | **30-year** |
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.40% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | 140 |
| Re-Offered Yield | 3.80% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **3.83%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| **Highway 407 (A, A)** | 130 |
| **NAV Canada (AA-, AA low)** | 100 |
| **GTAA (Aa3, A+)** | 100 |
| **Hydro One (A3/A/A high)** | 135 |

| Indicative New Issue Spreads - Jr. Sub Notes (Aa2/A) | |
|---|---|
| | **30-year** |
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.40% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | 170 |
| Re-Offered Yield | 4.10% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **4.13%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| **Ontario Power Generation (BBB+/A low)** | 155 |
| **Highway 407 (A, A)** | 130 |
| **Enbridge Gas Distribution (A-, A)** | 130 |
| **Hydro One (A3/A/A high)** | 135 |
| **Schedule 1 Bank ABS (A)** | 200 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-33 | 1-Jun-27 | 01-Jun-22 |
| 5.00% | 5.75% | 1.00% | 2.75% |
| 2.39% | 2.35% | 2.30% | 2.14% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 107 | 103 | 90 | 67 |
| 3.46% | 3.38% | 3.20% | 2.81% |
| 3.5 | 3.9 | 4.7 | 7.6 |
| **3.49%** | **3.42%** | **3.25%** | **2.89%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 79 | 76 | 66.5 | 44 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 134 | 117 | 100 | 80 |
| 117 | 100 | 85 | 65 |
| 138 | 119 | 100 | 80 |
| | 100 | | |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-33 | 1-Jun-27 | 01-Jun-22 |
| 5.00% | 5.75% | 1.00% | 2.75% |
| 2.39% | 2.35% | 2.30% | 2.14% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 132 | 126 | 112 | 88 |
| 3.71% | 3.61% | 3.42% | 3.02% |
| 3.5 | 3.9 | 4.7 | 7.6 |
| **3.74%** | **3.65%** | **3.47%** | **3.10%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 79 | 76 | 67 | 44 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 123 | 104 | 85 | 65 |
| 97 | 89 | 80 | 55 |
| 97 | 89 | 80 | 55 |
| 129 | 112 | 95 | 70 |

| | | | |
|---|---|---|---|
| | | | |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-33 | 1-Jun-27 | 01-Jun-22 |
| 5.00% | 5.75% | 1.00% | 2.75% |
| 2.39% | 2.35% | 2.30% | 2.14% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 162 | 156 | 135 | 107 |
| 4.01% | 3.91% | 3.65% | 3.21% |
| 3.5 | 3.9 | 4.7 | 7.6 |
| **4.04%** | **3.95%** | **3.70%** | **3.29%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 79 | 76 | 67 | 44 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 149 | 132 | 115 | 90 |
| 123 | 104 | 85 | 65 |
| 125 | 110 | 95 | 75 |
| 129 | 112 | 95 | 70 |
| 193 | 174 | 155 | 135 |
| | | | |
| | | | |
| | | | |
| | | | |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 01-Sep-20 | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 |
| 0.75% | 0.00% | 0.00% | 0.00% |
| 2.02% | 0.08% | 0.09% | 0.11% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 52 | -3 | -8 | -3 |
| 2.54% | 0.05% | 0.01% | 0.08% |
| 8.7 | 0.0 | 0.0 | 0.0 |
| **2.63%** | **0.05%** | **0.01%** | **0.08%** |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 28 | -5 | -4 | -5.5 |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 70 | 0 | 0 | 0 |
| 57 | 0 | 0 | 0 |
| 70 | 0 | 0 | 0 |
| | 0 | 0 | -2 |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 01-Sep-20 | 01-Dec-48 | 01-Jun-37 | 01-Jun-29 |
| 0.75% | 0.00% | 0.00% | 0.00% |
| 2.02% | 0.08% | 0.09% | 0.11% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 73 | -3 | -8 | -3 |
| 2.75% | 0.05% | 0.01% | 0.08% |
| 8.7 | 0.0 | 0.0 | 0.0 |
| **2.84%** | **0.05%** | **0.01%** | **0.08%** |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 28 | -5 | -4 | -6 |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 55 | -5 | -5 | -5 |
| 45 | -5 | -5 | -5 |
| 45 | -5 | -5 | -5 |
| 60 | -5 | -5 | -5 |

| | | | |
|---|---|---|---|
| | | | |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 01-Sep-20 | 01-Dec-48 | 1-Jun-37 | 1-Jun-29 |
| 0.75% | 0.00% | 0.00% | 0.00% |
| 2.02% | 0.08% | 0.09% | 0.11% |
| 0.0 | 0.0 | 0.0 | 0.0 |
| 92 | -3 | -8 | -3 |
| 2.94% | 0.05% | 0.01% | 0.08% |
| 8.7 | 0.0 | 0.0 | 0.0 |
| **3.03%** | **0.05%** | **0.01%** | **0.08%** |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 28 | -5 | -4 | -6 |

| | | | Week |
|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** |
| 75 | -10 | -10 | -10 |
| 55 | -5 | -5 | -5 |
| 60 | -5 | -5 | -5 |
| 60 | -5 | -5 | -5 |
| 120 | 0 | 0 | 0 |

| Bank Name | National Bank of Canada |
|---|---|
| Date | 4/19/2018 |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| 1-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| 0.00% | 0.00% | 0.00% |
| 0.13% | 0.13% | 0.09% |
| 0.0 | 0.0 | 0.0 |
| -3 | -3 | -3 |
| 0.10% | 0.10% | 0.06% |
| 0.0 | 0.0 | 0.0 |
| **0.10%** | **0.10%** | **0.06%** |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| -6 | -5.5 | -4 |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| 0 | 0 | 0 |
| 0 | 0 | 0 |
| 0 | 0 | 0 |
| 0 | 0 | 0 |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| 01-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| 0.00% | 0.00% | 0.00% |
| 0.13% | 0.13% | 0.09% |
| 0.0 | 0.0 | 0.0 |
| -3 | -3 | -3 |
| 0.10% | 0.10% | 0.06% |
| 0.0 | 0.0 | 0.0 |
| **0.10%** | **0.10%** | **0.06%** |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| -6 | -6 | -4 |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| -5 | 0 | 0 |
| -5 | -5 | -5 |
| -5 | -5 | -5 |
| -5 | -5 | 0 |

| | | |
|---|---|---|
| | | |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| 1-Jun-27 | 01-Jun-22 | 01-Sep-20 |
| 0.00% | 0.00% | 0.00% |
| 0.13% | 0.13% | 0.09% |
| 0.0 | 0.0 | 0.0 |
| -3 | -3 | -3 |
| 0.10% | 0.10% | 0.06% |
| 0.0 | 0.0 | 0.0 |
| **0.10%** | **0.10%** | **0.06%** |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| -6 | -6 | -4 |

| over Week | | |
|---|---|---|
| **10-year** | **5-year** | **3-year** |
| -10 | -5 | -5 |
| -5 | 0 | 0 |
| -5 | -5 | 0 |
| -5 | -5 | 0 |
| 0 | 0 | 0 |

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | 30-year |
|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | **2.31%** |
| Curve Adjustment (bp) | **0.0** |
| Spread to GoC Curve (bp) | **106** |
| Re-Offered Yield | 3.37% |
| Commission (bp) | 2.7 |
| **All-in Yield** | **3.39%** |

| Primary Comparable (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | **81** |

| Other Comparables (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| **Canada Mortgage & Housing Corp (AAA/Aaa/AAA)** | **n/a** |
| **City of Toronto (AA/Aa1/AA)** | **103** |
| **Hydro One Inc. (A(H)/A3/A)** | **142** |
| **Ontario Power Generation Inc. (A(low)/-/BBB+)** | **162** |
| **Toronto Hydro Corporation (A/-/A)** | **135** |
| **Canadian National Railway Co (A/A2/A)** | **135** |
| **Greater Toronto Airports Authority (A(high)/Aa3/A+)** | **102** |
| **NAV Canada (AA(low)/Aa2/AA-)** | **101** |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | 30-year |
|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.31% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | **138** |
| Re-Offered Yield | 3.69% |
| Commission (bp) | 2.8 |
| **All-in Yield** | **3.71%** |

| Primary Comparable (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 81 |

| Other Comparables (S&P/Moody's/ DBRS) | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| **RBC Sr-Sub.** | **n/a** |

| | |
|---|---|
| | |

| Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2) | |
|---|---|
| | **30-year** |
| Benchmark Canada Bond Maturity | 01-Dec-48 |
| Benchmark Canada Bond Coupon | 2.75% |
| Benchmark Yield | 2.31% |
| Curve Adjustment (bp) | 0.0 |
| Spread to GoC Curve (bp) | **174** |
| Re-Offered Yield | 4.05% |
| Commission (bp) | 2.9 |
| **All-in Yield** | **4.08%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 81 |

| **Other Comparables (S&P/Moody's/ DBRS)** | |
|---|---|
| Spread to GoC Curve (bp) | **30-year** |
| | |

The indicative price is not an offer to purchase or sell any instrument or enter into, transfer and assign, or terminate a an indicative price of an instrument or transaction such as the instrument or transaction for which an indicative price i prices or valuations for the instrument or transaction and can be less favourable to you.

The indicative price does not necessarily reflect the price or valuation used by RBC for different purposes, such as ac RBC to continue to provide prices to you in regard to this product or transaction or to provide prices to you in regard t any transaction with any counterparty at this price.

The indicative price is provided by way of example only, and is not intended to replace or supplant advice of your aud EVENT SHALL RBC OR ITS AGENTS OR OFFICERS BE LIABLE FOR ANY DAMAGES WHATSOEVER (INCLUDI the indicative price is adequate or appropriate for your purposes.

The information provided in this valuation (the “Information”) (i) is intended for your information only and is not to be d the fullest extent permissible by law, shall have no liability whatsoever to you or any other person or party for any loss

-- Confidential --

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Mar-23 |
| 5.00% | 5.75% | 1.00% | 1.75% |
| **2.44%** | **2.21%** | **2.16%** | **2.01%** |
| **0.6** | **2.9** | **2.4** | **0.6** |
| **107** | **106** | **96** | **74** |
| 3.52% | 3.30% | 3.14% | 2.76% |
| 3.9 | 3.8 | 4.7 | 7.6 |
| **3.56%** | **3.34%** | **3.19%** | **2.84%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| **75** | **81** | **71** | **49** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| **n/a** | **n/a** | **41** | **33** |
| **97** | **100** | **88** | **65** |
| **n/a** | **n/a** | **98** | **66** |
| **n/a** | **n/a** | **120** | **89** |
| **n/a** | **n/a** | **95** | **62** |
| **n/a** | **n/a** | **95** | **71** |
| **n/a** | **n/a** | **81** | **61** |
| **n/a** | **n/a** | **81** | **61** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 01-Jun-37 | 01-Jun-29 | 01-Jun-27 | 01-Mar-23 |
| 5.00% | 5.75% | 1.00% | 1.75% |
| 2.44% | 2.21% | 2.16% | 2.01% |
| 0.6 | 2.9 | 2.4 | 0.6 |
| **137** | **138** | **128** | **106** |
| 3.82% | 3.62% | 3.46% | 3.08% |
| 0.0 | 3.9 | 4.8 | 7.6 |
| **3.82%** | **3.66%** | **3.51%** | **3.16%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 75 | 81 | 71 | 49 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| **n/a** | **n/a** | **83** | **63** |

| | | | |
|---|---|---|---|
| | | | |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 1-Jun-37 | 1-Jun-29 | 1-Jun-27 | 01-Mar-23 |
| 5.00% | 5.75% | 1.00% | 1.75% |
| 2.44% | 2.21% | 2.16% | 2.01% |
| 0.6 | 2.9 | 2.4 | 0.6 |
| **171** | **174** | **164** | **142** |
| 4.16% | 3.98% | 3.82% | 3.44% |
| 0.0 | 4.0 | 4.9 | 7.7 |
| **4.16%** | **4.02%** | **3.87%** | **3.52%** |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| 75 | 81 | 71 | 49 |

| Current | | | |
|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** |
| | | | |

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s being provided to you may differ substantially from a firm price of such instrument or transaction. The indicative price

:counting, internal reporting or capital adequacy purposes. The difference between the indicative price and the price or
o any other existing or future transactions between you and RBC. The indicative price does not in any way amend, mo

itors, lawyers and other advisors, and does not create any relationship between RBC and you or any individual or entit
NG, WITHOUT LIMITATION, DAMAGES FOR LOSS OF PROFITS, BUSINESS INTERRUPTION, LOSS OF INFORM

lisclosed to, provided to, or used by, any other person or party; (ii) is supplied by us in good faith; and (iii) is based on i
; or damage, direct or indirect, arising from the use of the Information.

| Bank Name | |
|---|---|
| Date | |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 01-Mar-21 | | | | | |
| 0.75% | | | | | |
| 1.92% | 5.2 | 5.1 | 4.5 | 3.5 | 2.1 |
| 1.1 | - | -0.1 | 0.1 | 0.5 | 0.2 |
| 56 | - | - | - | - | 1.0 |
| 2.50% | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |
| 8.7 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| **2.58%** | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 31 | 0.5 | - | - | -0.5 | 1.5 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 18 | | | | 1.5 | 1.0 |
| 46 | - | - | 1.5 | -0.5 | 2.0 |
| 56 | 1.0 | | | 1.0 | 1.0 |
| 77 | - | | | - | - |
| 52 | - | | | - | - |
| 62 | 1.0 | | | 2.0 | 2.0 |
| 51 | 1.0 | | | 1.0 | 1.0 |
| 51 | 1.0 | | | 1.0 | 1.0 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 01-Mar-21 | | | | | |
| 0.75% | | | | | |
| 1.92% | | | | | |
| 1.1 | | | | | |
| 88 | - | - | - | - | 1.0 |
| 2.82% | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |
| 8.8 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 |
| **2.90%** | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| 31 | 0.5 | - | - | -0.5 | 1.5 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| 3-year | 30-year | 20-year | 15-year | 10-year | 5-year |
| n/a | | | | 15.0 | 18.0 |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 01-Mar-21 | | | | | |
| 0.75% | | | | | |
| 1.92% | | | | | |
| 1.1 | | | | | |
| **124** | - | - | - | - | 1.0 |
| 3.18% | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |
| 8.8 | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 |
| **3.26%** | 5.2 | 5.0 | 4.6 | 4.0 | 3.3 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| 31 | 0.5 | - | - | -0.5 | 1.5 |

| | Week over Week | | | | |
|---|---|---|---|---|---|
| **3-year** | **30-year** | **20-year** | **15-year** | **10-year** | **5-year** |
| | | | | | |

fer, or an indication of RBC's willingness to make such an offer at any time. As a general matter, and particularly in times of distressed markets
e may vary significantly from prices or valuation estimates available from other sources. If RBC decides to quote a firm price, the firm price can

valuation used for RBC's internal purposes may be substantial and not immaterial. The provision of the indicative price to you by RBC does n
dify, alter or restate the terms and conditions to which any existing instruments or transactions are subject. This indicative price does not comm

y at RBC by using the indicative price. The indicative price is provided without any warranty, express or implied, as to its legal effect or complet
MATION) ARISING OUT OF THE USE OF OR INABILITY TO USE THE MATERIALS. You should discuss with your auditors, lawyers and othe

nformation which we believe, but do not guarantee, to be accurate or complete. RBC makes no representation or warranty with respect to the I

| RBC |
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| 19-Apr-18 |

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| --- | --- |
| | **3-year** |
| | |
| | 1.7 |
| | 0.3 |
| | -1.0 |
| | 1.0 |
| | 0.0 |
| | 1.0 |

| | |
| --- | --- |
| | **3-year** |
| | -0.5 |

| | |
| --- | --- |
| | **3-year** |
| | - |
| | 0.5 |
| | 1.0 |
| | - |
| | - |
| | 1.0 |
| | 1.0 |
| | 1.0 |
| | |

| | |
| --- | --- |
| | **3-year** |
| | |
| | -1.0 |
| | 1.0 |
| | 0.00 |
| | 1.0 |

| | |
| --- | --- |
| | **3-year** |
| | -0.5 |

| | |
| --- | --- |
| | **3-year** |
| | |

| 3-year |
| --- |
| -1.0 |
| 1.0 |
| 0.00 |
| 1.0 |

| 3-year |
| --- |
| -0.5 |

| 3-year |
| --- |

or limited liquidity,
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ot bind or obligate
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ɛr advisors whether

Information and, to

| icative New Issue Spreads - Senior Notes (AAA/A | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.41% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **+117** | **+107** |
| Re-Offered Yield | 3.60% | 3.49% |
| Commission (bp) | 2.4 | 3.7 |
| **All-in Yield** | **3.62%** | **3.53%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **OPG** | 165 | |
| **CPP** | 82 | |
| **BNS - Denior Deposit Notes** | 132 | |
| **Golden Credit Card Trust** | | |
| **Master Credit Card Trust** | | |

| ndicative New Issue Spreads - Sub Notes (AA/Aa2 | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.41% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **+152** | **+142** |
| Re-Offered Yield | 3.95% | 3.84% |
| Commission (bp) | 2.4 | 3.7 |
| **All-in Yield** | **3.97%** | **3.88%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| Other Comparables (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **Golden Credit Card Trust** | | |
| **Master Credit Card Trust** | | |

| **dicative New Issue Spreads - Jr. Sub Notes (A/Aa** | | |
|---|---|---|
| | **30-year** | **20-year** |
| Benchmark Canada Bond Maturity | 01-Dec-48 | 1-Jun-37 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.43% | 2.41% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **+190** | **+180** |
| Re-Offered Yield | 4.33% | 4.22% |
| Commission (bp) | 2.4 | 3.7 |
| **All-in Yield** | **4.35%** | **4.26%** |

| Primary Comparable (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| Other Comparables (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **Golden Credit Card Trust** | | |
| **Master Credit Card Trust** | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1-Jun-33 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | |
| 5.75% | 1.00% | 1.75% | 0.75% | |
| 2.39% | 2.33% | 2.17% | 2.04% | 0.09% |
| (0.1) | 1.4 | 1.4 | 1.3 | 0 |
| **+99** | **+92** | **+70** | **+55** | 14 |
| 3.38% | 3.26% | 2.89% | 2.61% | 0.23% |
| 3.6 | 4.5 | 7.7 | 8.6 | 0 |
| **3.41%** | **3.31%** | **2.96%** | **2.69%** | **0.23%** |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 76.5 | 67 | 45 | 28 | 0 |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| | 120 | 95 | 81 | 0 |
| | 72 | 49 | 32 | 0 |
| | 102 | 86 | 76 | 0 |
| | 99 | 83 | 72 | |
| | 99 | 83 | 72 | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1-Jun-33 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | |
| 5.75% | 1.00% | 1.75% | 0.75% | |
| 2.39% | 2.33% | 2.17% | 2.04% | 0.09% |
| (0.1) | 1.4 | 1.4 | 1.3 | 0 |
| **+129** | **+122** | **+100** | **+85** | 15 |
| 3.68% | 3.56% | 3.19% | 2.91% | 0.24% |
| 3.6 | 4.5 | 7.7 | 8.6 | 0 |
| **3.71%** | **3.61%** | **3.26%** | **2.99%** | **0.24%** |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 76.5 | 67 | 45 | 28 | 0 |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| | 99 | 83 | 72 | |
| | 99 | 83 | 72 | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 1-Jun-33 | 1-Jun-27 | 01-Mar-23 | 01-Mar-21 | |
| 5.75% | 1.00% | 1.75% | 0.75% | |
| 2.39% | 2.33% | 2.18% | 2.04% | 0.09% |
| (0.1) | 1.4 | 1.4 | 1.3 | 0 |
| **+159** | **+152** | **+130** | **+115** | 18 |
| 3.98% | 3.86% | 3.49% | 3.21% | 0.27% |
| 3.6 | 4.5 | 7.7 | 8.6 | 0 |
| **4.01%** | **3.91%** | **3.57%** | **3.29%** | **0.27%** |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 76.5 | 67 | 45 | 28 | 0 |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| | 99 | 83 | 72 | |
| | 99 | 83 | 72 | |

| | |
|---|---|
| **Bank Name** | BNS |
| **Date** | 4/19/2018 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |
| 0.09% | 0.09% | 0.08% | 0.06% | 0.03% |
| 0 | 0 | 0 | 0 | 1 |
| 5 | 3 | 5 | 2 | 3 |
| 0.14% | 0.12% | 0.13% | 0.08% | 0.07% |
| 1 | 0 | 0 | 0 | 0 |
| **0.14%** | **0.12%** | **0.13%** | **0.08%** | **0.07%** |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| 0 | 0 | 0 | 0 | 0 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |
| 0.09% | 0.09% | 0.08% | 0.06% | 0.03% |
| 0 | 0 | 0 | 0 | 1 |
| 8 | 4 | 6 | 3 | 4 |
| 0.17% | 0.13% | 0.14% | 0.09% | 0.08% |
| 1 | 0 | 0 | 0 | 0 |
| **0.17%** | **0.13%** | **0.14%** | **0.10%** | **0.08%** |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| 0 | 0 | 0 | 0 | 0 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |
| 0.09% | 0.09% | 0.08% | 0.06% | 0.03% |
| 0 | 0 | 0 | 0 | 1 |
| 13 | 4 | 6 | 3 | 4 |
| 0.22% | 0.13% | 0.14% | 0.10% | 0.08% |
| 1 | 0 | 0 | 0 | 0 |
| **0.22%** | **0.13%** | **0.14%** | **0.10%** | **0.08%** |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| 0 | 0 | 0 | 0 | 0 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | 0 | 0 | 0 |
| | | 0 | 0 | 0 |

| Indicative New Issue Spreads - Senior Notes (AAA/Aa2) | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 30-Nov-44 | 31-May-33 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.45% | 2.44% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **115** | **107** |
| Re-Offered Yield | 3.60% | 3.52% |
| Commission (bp) | 2.4 | 3.2 |
| **All-in Yield** | **3.62%** | **3.55%** |

| Primary Comparable (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| Other Comparables (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **OPB Finance Trust (AA+/-/AA(H))** | 107 | 97 |
| **Covered Bond - Bank (AAA/Aaa/AAA)** | N/A | N/A |
| **Hydro One Inc. (A/A3/AH)** | 134 | 124 |

| Indicative New Issue Spreads - Sub Notes (AA/Aa2) | 30-year | 20-year |
|---|---|---|
| Benchmark Canada Bond Maturity | 30-Nov-44 | 31-May-33 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.45% | 2.44% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **145** | **137** |
| Re-Offered Yield | 3.90% | 3.82% |
| Commission (bp) | 2.4 | 3.2 |
| **All-in Yield** | **3.92%** | **3.85%** |

| Primary Comparable (S&P/Moody's/ DBRS) | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |

| | | |
|---|---|---|
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **MBS** | | |
| **ABS** | | |

| **Indicative New Issue Spreads - Jr. Sub Notes (A/Aa2)** | **30-year** | **20-year** |
|---|---|---|
| Benchmark Canada Bond Maturity | 30-Nov-44 | 31-May-33 |
| Benchmark Canada Bond Coupon | 2.75% | 5.00% |
| Benchmark Yield | 2.45% | 2.44% |
| Curve Adjustment (bp) | 0.0 | 0.6 |
| Spread to GoC Curve (bp) | **175** | **167** |
| Re-Offered Yield | 4.20% | 4.12% |
| Commission (bp) | 2.4 | 3.2 |
| **All-in Yield** | **4.22%** | **4.15%** |

| **Primary Comparable (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| Province of Ontario (AA- / Aa2 / AA(L)) | 78 | 78 |

| **Other Comparables (S&P/Moody's/ DBRS)** | | |
|---|---|---|
| Spread to GoC Curve (bp) | **30-year** | **20-year** |
| **MBS** | | |
| **ABS** | | |

| | |
|---|---|
| **Bank Name** | TD Securuties |
| **Date** | 4/16/2018 |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 | - |
| 5.75% | 1.00% | 1.50% | 0.75% | - |
| 2.38% | 2.35% | 2.21% | 2.05% | 0.082% |
| 2.5 | 1.6 | 0.0 | 1.6 | - |
| **97** | **90** | **60** | **45** | -2 |
| 3.38% | 3.26% | 2.81% | 2.52% | 0.06% |
| 3.6 | 4.5 | 7.4 | 8.7 | - |
| **3.41%** | **3.31%** | **2.88%** | **2.61%** | **0.06%** |

| | | | Current | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 73 | 68 | 45 | 29 | (5.0) |

| | | | Current | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 92 | 88 | 65 | 44 | (9) |
| N/A | 85 | 66 | 53 | N/A |
| 100 | 92 | 72 | 58 | (4) |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 | - |
| 5.75% | 1.00% | 1.50% | 0.75% | - |
| 2.38% | 2.35% | 2.21% | 2.05% | 0.082% |
| 2.5 | 1.6 | 0.0 | 1.6 | - |
| **127** | **120** | **90** | **75** | -2 |
| 3.68% | 3.56% | 3.11% | 2.82% | 0.06% |
| 3.6 | 4.5 | 7.4 | 8.7 | - |
| **3.71%** | **3.61%** | **3.18%** | **2.91%** | **0.06%** |

| | | | Current | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |

| | | | | |
|---|---|---|---|---|
| 73 | 68 | 45 | 29 | (5.0) |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| | | | | |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 31-May-25 | 31-May-23 | 31-May-19 | 28-Feb-17 | - |
| 5.75% | 1.00% | 1.50% | 0.75% | - |
| 2.38% | 2.35% | 2.21% | 2.05% | 0.082% |
| 2.5 | 1.6 | 0.0 | 1.6 | - |
| **157** | **150** | **120** | **105** | -2 |
| 3.98% | 3.86% | 3.41% | 3.12% | 0.06% |
| 3.6 | 4.5 | 7.4 | 8.7 | - |
| **4.01%** | **3.91%** | **3.48%** | **3.21%** | **0.06%** |

| | | | Current | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| 73 | 68 | 45 | 29 | (5.0) |

| Current | | | | |
|---|---|---|---|---|
| **15-year** | **10-year** | **5-year** | **3-year** | **30-year** |
| | | | | |

| | |
|---|---|
| **Bank Name** | TD Securuties |
| **Date** | 4/16/2018 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| - | - | - | - | - |
| - | - | - | - | - |
| 0.090% | 0.121% | 0.134% | 0.129% | 0.084% |
| - | - | - | - | - |
| -2 | -2 | -2 | -2 | -2 |
| 0.07% | 0.09% | 0.11% | 0.11% | 0.06% |
| - | - | - | - | - |
| **0.07%** | **0.09%** | **0.11%** | **0.11%** | **0.06%** |

| | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| (5.0) | (6.0) | (7.0) | (6.0) | (4.0) |

| | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| (9) | -9 | (4) | 1 | -2 |
| N/A | N/A | (1) | - | 2 |
| (4) | - | - | 2 | 1 |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| - | - | - | - | - |
| - | - | - | - | - |
| 0.090% | 0.121% | 0.134% | 0.129% | 0.084% |
| - | - | - | - | - |
| -2 | -2 | -2 | -2 | -2 |
| 0.07% | 0.09% | 0.11% | 0.11% | 0.06% |
| - | - | - | - | - |
| **0.07%** | **0.09%** | **0.11%** | **0.11%** | **0.06%** |

| | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |

| | | | | |
|---|---|---|---|---|
| (5.0) | (6.0) | (7.0) | (6.0) | (4.0) |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| - | - | - | - | - |
| - | - | - | - | - |
| 0.090% | 0.121% | 0.134% | 0.129% | 0.084% |
| - | - | - | - | - |
| -2 | -2 | -2 | -2 | -2 |
| 0.07% | 0.09% | 0.11% | 0.11% | 0.06% |
| - | - | - | - | - |
| **0.07%** | **0.09%** | **0.11%** | **0.11%** | **0.06%** |

| | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| (5.0) | (6.0) | (7.0) | (6.0) | (4.0) |

| Week over Week | | | | |
|---|---|---|---|---|
| **20-year** | **15-year** | **10-year** | **5-year** | **3-year** |
| | | | | |

**PROTOCOL DOCUMENT- SUBORDINATED AND JUNIOR SUBORDINATED NOTES**

| | |
|---|---|
| **Interpretation** | Unless inconsistent with the express terms or provisions hereof, terms used herein have the meanings ascribed in the Trust Indenture (the "**Trust Indenture**") dated as of ●, 2017 between the Fair Hydro Trust, a trust existing under the laws of the Province of Ontario (the "**Issuer**") and BNY Trust Company of Canada, a trust company existing under the laws of Canada (the "**Indenture Trustee**"). |
| **Financial Services Manager** | The interest rate applicable to each Series of Subordinated Notes and/or Junior Subordinated Notes, shall be established by Ontario Power Generation Inc., acting as financial services manager of the Issuer (the "**FSM**"), in accordance with procedures set out herein. |
| **Interest Rate:** | For any Series of Subordinated Notes or Junior Subordinated Notes, the interest rate shall be the aggregate of the applicable Base Rate and the Applicable Spread. |
| **Base Rate:** | "Base Rate" means:<br><br>(a) for Term Notes: an annual rate of interest comprised of the applicable yield for the Benchmark Government of Canada bonds listed at the time and with the same term of such Series of Subordinated Notes or Junior Subordinated Notes, as applicable. In the event that there are no Benchmark Government of Canada bonds listed at the time of issuance with the same term, the rate shall be established by interpolating the terms of the two Benchmark Government of Canada bonds that are closest to the term of the Series of Subordinated Notes or Junior Subordinated Notes, as applicable, one being for a longer term and the other being for a shorter term; and<br><br>(b) for Warehouse Notes: an annual interest rate equal to the [**all-in annual funding costs under the Warehouse Facility related to the senior tranche, expressed in basis points].** |
| **Applicable Spread:** | "Applicable Spread" means the additional interest in basis points over the Base Rate applicable to a particular Series of Subordinated Notes or Junior Subordinated Notes as determined by the FSM applying the procedures set out below:<br><br>(a) for Subordinated Term Notes and Junior Subordinated Term Notes: the FSM will solicit from time to time, but no less frequently than on a weekly basis, from at least five commercial banks in Canada, a survey of indicative spreads (collectively, the **"Indicative Spreads"** and each an "**Indicative Spread**") applicable to capital market debt issuances having features comparable to each of the Subordinated Term Notes and the Junior Subordinated Terms Notes, |

| | |
|---|---|
| | including credit rating and tenor. The Applicable Spread for Subordinated Term Notes or Junior Subordinated Term Notes, as applicable, will be the simple average of the respective Indicative Spreads after excluding the highest and the lowest Indicative Spread;<br><br>(b) for Subordinated Warehouse Notes: the FSM will solicit from time to time, but no less frequently than on an annual basis, from at least five commercial banks in Canada, a survey of Indicative Rates applicable to commercial paper issuances having features comparable to the Subordinated Warehouse Notes including credit rating and tenor. The Applicable Spread for Subordinated Warehouse Notes will be the simple average of the respective Indicative Spreads, after excluding the highest and the lowest Indicative Spread;<br><br>(c) for Junior Subordinated Warehouse Notes: while the Junior Subordinated Term Notes are rated Investment Grade, the Applicable Spread for the Junior Subordinated Warehouse Notes shall be equal to the Applicable Spread derived above for the Subordinated Warehouse Notes. If the Junior Subordinated Term Notes are rated below Investment Grade, the Applicable Spread for the Junior Subordinated Warehouse Notes will equal to the Applicable Spread for the Subordinated Warehouse Notes plus 100 bps.<br><br>For the purposes of this section "Investment Grade" means a credit rating from DBRS above or equal to "BBB low", or from Moody's above or equal to "Baa3". |
| **Credit Rating** | In order to facilitate the survey of Indicative Interest Rates, the FSM will solicit from time to time from DBRS and/or Moody's a credit rating, which may include a shadow rating for the Subordinated Notes and the Junior Subordinated Notes. |

# Subordinated Debt Pricing Protocol Agreement

THIS AGREEMENT is made as of •, 2017

BETWEEN

**ONTARIO POWER GENERATION INC**., a corporation incorporated under the laws of Ontario ("**OPG**"), solely in its capacity as financial services manager (the "**FSM**") of the Fair Hydro Trust (the "**Issuer**"), a trust existing under the laws of the Province of Ontario

- and -

**HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO**, (the "**Province**") as represented by the Minister of Energy

WHEREAS the Issuer and BNY Trust Company of Canada entered into that certain trust indenture (as supplemented from time to time, the "**Trust Indenture**") dated ■, 2017;

AND WHEREAS pursuant to the Trust Indenture the Issuer may issue, from time to time, certain Subordinated Notes and Junior Subordinated Notes;

AND WHEREAS the FSM and the Province have agreed to establish herein the procedures for establishing the interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes where such Notes are to be issued only to OPG or its Affiliates;

NOW THEREFORE, in consideration of the premises and the covenants and agreements herein contained, the parties agree as follows:

## ARTICLE 1 - INTERPRETATION

### 1.01 Definitions

In this Agreement, unless something in the subject matter or context is inconsistent therewith terms used herein have the meanings ascribed in the Trust Indenture. In addition, the following terms shall have the following meanings:

(a) "**Applicable Spread**" has the meaning ascribed to such term in section 2.04(c);

(b) "**Base Rate**" has the meaning ascribed to such term in section 2.03(a) or (b), as applicable;

(c) "**Junior Subordinated Term Note**" means a Junior Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement;

(d) "**Junior Subordinated Warehouse Note**" means a Junior Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement;

(e) "**Subordinated Term Note**" means a Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement; and

(f) "**Subordinated Warehouse Note**" means a Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement.

1.02 **Headings**

The division of this Agreement into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof.

## ARTICLE 2 - INTEREST RATE PROTOCOLS

2.01 **Interest Rate Protocols**

The interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes that are issued only to OPG or its Affiliates shall be established by the FSM in accordance with the procedures set out herein.

2.02 **Composite Interest Rate**

For any Series of Subordinated Notes or Junior Subordinated Notes that are issued only to OPG or its Affiliates, the interest rate shall be the aggregate of the applicable Base Rate and the Applicable Spread.

2.03 **Base Rate**

(a) For Subordinated Term Notes and Junior Subordinated Term Notes, the "Base Rate" shall be an annual rate of interest comprised of the applicable yield for the Benchmark Government of Canada bonds listed at the time and with the same term as that of the Series of Subordinated Notes or Series of Junior Subordinated Notes, as applicable. In the event that there are no such Benchmark Government of Canada bonds listed at the time of issuance, the applicable Base Rate of interest shall be established by interpolating on a straight line basis the terms of the two Benchmark Government of Canada bonds that are closest to the term of the applicable Series of Subordinated Term Notes or Series of Junior Subordinated Term Notes, as applicable, one being for a longer term and the other being for a shorter term; and

(b) For Subordinated Warehouse Notes and Junior Subordinated Warehouse Notes, the "Base Rate" shall be an annual interest rate equal to the all-in funding costs under the related Warehouse Obligations, expressed as a rate per annum, as

determined by the FSM acting reasonably, or at any time when there are no Warehouse Obligations outstanding the "Base Rate" shall be the average of the posted "prime rate of interest" published by the five largest Canadian banks at such time.

2.04 **Applicable Spread**

(a) Prior to the issuance of any new Subordinated Term Notes or Junior Subordinated Term Notes, the FSM will solicit from at least five investment dealers in Canada, a survey of indicative spreads over the applicable Base Rate (collectively, the "**Indicative Spreads**" and each an "**Indicative Spread**") applicable to capital market debt issuances having features comparable to each of the proposed Series of Subordinated Term Notes and Junior Subordinated Term Notes, having regard to the expected credit rating and tenor. Such solicitation of Indicative Spreads shall occur on the pricing date of the applicable Series of Subordinated Term Notes and Junior Subordinated Term Notes and may, at the FSM's option, also occur on other dates selected by the FSM provided that no such date is more than **one week** prior to the pricing date. The Applicable Spread for Subordinated Term Notes or Junior Subordinated Term Notes, as applicable, will be the simple average of the respective Indicative Spreads after excluding the highest and the lowest Indicative Spread for each day (not more than one week prior to the pricing date) that Indicative Spreads were provided;

(b) For Subordinated Warehouse Notes the FSM will solicit from time to time, but no less frequently than on an annual basis, from at least five investment dealers in Canada, a survey of Indicative Spreads over the applicable Base Rate applicable to commercial paper issuances having features comparable to the Subordinated Warehouse Notes including credit rating and tenor. The Applicable Spread for Subordinated Warehouse Notes will be the simple average of the respective Indicative Spreads, after excluding the highest and the lowest Indicative Spread;

(c) The Applicable Spread for Junior Subordinated Warehouse Notes shall be equal to the Applicable Spread derived from Section 2.04(b) for the Subordinated Warehouse Notes, provided the Junior Subordinated Term Notes are rated Investment Grade. If the Junior Subordinated Term Notes are rated below Investment Grade, the Applicable Spread for the Junior Subordinated Warehouse Notes will equal to the Applicable Spread for the Subordinated Warehouse Notes plus 100 bps.

For the purposes of this section "Investment Grade" means an "approved rating" from at least one "designated rating organization" (as such terms are defined for securities law purposes).

2.05 **Credit Ratings**

In order to facilitate the survey of Indicative Spreads, the FSM will solicit from time to time, from an approved rating organization (as such term is defined for securities laws

purposes), a credit rating, which may include a shadow rating, for the Subordinated Notes and the Junior Subordinated Notes.

## ARTICLE 3 - GENERAL

### 3.01 Benefit of the Agreement

This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the parties.

### 3.02 Entire Agreement

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancel and supersede any prior understandings and agreements between the parties with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Agreement.

### 3.03 Assignment, Amendments and Waivers

No assignment or amendment to this Agreement will be valid or binding unless set forth in writing and duly executed by all of the parties. No waiver of any breach of any provision of this Agreement will be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, will be limited to the specific breach waived.

### 3.04 Severability

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability will attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof will continue in full force and effect.

### 3.05 Governing Law

This Agreement is governed by and will be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. For the purpose of all legal proceedings this Agreement will be deemed to have been performed in the Province of Ontario and the courts of the Province of Ontario will have exclusive jurisdiction to entertain any action arising under this Agreement. The parties hereby attorn to the exclusive jurisdiction of the courts of the Province of Ontario.

### 3.06 Counterparts

This Agreement may be executed in any number of counterparts, each of which will be deemed to be an original and all of which taken together will be deemed to constitute one and the same instrument.

3.07 **Electronic Execution**

Any party may deliver an executed signature page to this Agreement by electronic transmission and such delivery will be as effective as delivery of a manually executed copy of the Agreement by such party.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF the parties have executed this Agreement.

**ONTARIO POWER GENERATION INC.**
solely in its capacity as Financial Services Manager of the Fair Hydro Trust

Per: _____
Ken Hartwick
Chief Financial Officer and Senior Vice President

Per: _____
John Lee
Vice President- Treasurer

**HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO**, as represented by the Minister of Energy

Per: _____
[Name]
[Position]

Draft: November 29, 2017

**Subordinated Debt Pricing Protocol Agreement**

THIS AGREEMENT is made as of •, 2017

BETWEEN

**ONTARIO POWER GENERATION INC**., a corporation incorporated under the laws of Ontario ("**OPG**"), solely in its capacity as financial services manager (the "**FSM**") of the Fair Hydro Trust (the "**Issuer**"), a trust existing under the laws of the Province of Ontario

- and -

**HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO**, (the "**Province**") as represented by the Minister of Energy

WHEREAS the Issuer and BNY Trust Company of Canada entered into that certain trust indenture (as supplemented from time to time, the "**Trust Indenture**") dated ■, 2017;

AND WHEREAS pursuant to the Trust Indenture the Issuer may issue, from time to time, certain Subordinated Notes and Junior Subordinated Notes;

AND WHEREAS the FSM and the Province have agreed to establish herein the procedures for establishing the interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes where such Notes are to be issued only to OPG or its Affiliates;

NOW THEREFORE, in consideration of the premises and the covenants and agreements herein contained, the parties agree as follows:

## ARTICLE 1 - INTERPRETATION

1.01 **Definitions**

In this Agreement, unless something in the subject matter or context is inconsistent therewith terms used herein have the meanings ascribed in the Trust Indenture. In addition, the following terms shall have the following meanings:

(a) "**Applicable Spread**" has the meaning ascribed to such term in section 2.04(c);

(b) "**Base Rate**" has the meaning ascribed to such term in section 2.03(a) or (b), as applicable;

(c) "**Junior Subordinated Term Note**" means a Junior Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement;

**Commented [TS(1]:** Not clear to me what the role is for the Ministry except to approve an approach that FSM is putting forward. Are there any ongoing obligations/reporting?

Given the technical nature of the approval, and that it appears to be based on the approach for OEFC lending to OPG for general corporate purposes, I would strongly recommend that OFA/Ministry of Finance co-sign this document

**Commented [JK2R1]:** This is a good question if Energy does not want to formalize.

(d) "**Junior Subordinated Warehouse Note**" means a Junior Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement;

(e) "**Subordinated Term Note**" means a Subordinated Note that is not incurred pursuant to a Warehouse Facility Agreement; and

(f) "**Subordinated Warehouse Note**" means a Subordinated Note that is incurred pursuant to a Warehouse Facility Agreement.

1.02 **Headings**

The division of this Agreement into Articles and Sections and the insertion of headings are for convenience of reference only and do not affect the construction or interpretation of this Agreement. The terms "hereof", "hereunder" and similar expressions refer to this Agreement and not to any particular Article, Section or other portion hereof.

## ARTICLE 2 - INTEREST RATE PROTOCOLS

2.01 **Interest Rate Protocols**

The interest rate applicable to each Series of Subordinated Notes and Junior Subordinated Notes that are issued only to OPG or its Affiliates shall be established by the FSM in accordance with the procedures set out herein.

2.02 **Composite Interest Rate**

For any Series of Subordinated Notes or Junior Subordinated Notes that are issued only to OPG or its Affiliates, the interest rate shall be the aggregate of the applicable Base Rate and the Applicable Spread.

2.03 **Base Rate**

(a) For Subordinated Term Notes and Junior Subordinated Term Notes, the "Base Rate" shall be an annual rate of interest comprised of the applicable yield for the Benchmark Government of Canada bonds listed at the time and with the same term as that of the Series of Subordinated Notes or Series of Junior Subordinated Notes, as applicable. In the event that there are no such Benchmark Government of Canada bonds listed at the time of issuance, the applicable Base Rate of interest shall be established by interpolating on a straight line basis the terms of the two Benchmark Government of Canada bonds that are closest to the term of the applicable Series of Subordinated Term Notes or Series of Junior Subordinated Term Notes, as applicable, one being for a longer term and the other being for a shorter term; and

(b) For Subordinated Warehouse Notes and Junior Subordinated Warehouse Notes, the "Base Rate" shall be an annual interest rate equal to the all-in funding costs under the related Warehouse Obligations, expressed as a rate per annum, as

**Commented [TS(3]:** As it is structured, while the approach may be consistent with how OEFC lends to OPG for general coroporate purpose, there does not seem to be a check in place on the interest rates. The rates will be a large driver of ratepayer impacts, particulary in the long run.

I would suggest a mechanism that OPG check in with OFA on the base rate and applicable spread prior to the issuance of notes. OFA would then communicate its satisfication with OPG's survey results to OPG and Energy. This may need further discussion if this oversight has other unintended consequences.

**Commented [JK4R3]:** CY: We can be involved – doing back to back, issue to market and sub notes, Canadas will be the same for both and only difference will spread will be different; protocol is that we all get the spread from the dealers; OFA can help monitor; Energy can call Carlos always welcome; likely not need to be consulted however as spreads are things we already get [for OEFC, for example]; will be the same process even though for Trust; will be the same dealers as in OEFC's example

determined by the FSM acting reasonably, or at any time when there are no Warehouse Obligations outstanding the "Base Rate" shall be the average of the posted "prime rate of interest" published by the five largest Canadian banks at such time.

2.04 **Applicable Spread**

(a) Prior to the issuance of any new Subordinated Term Notes or Junior Subordinated Term Notes, the FSM will solicit from at least five investment dealers in Canada, a survey of indicative spreads over the applicable Base Rate (collectively, the "**Indicative Spreads**" and each an "**Indicative Spread**") applicable to capital market debt issuances having features comparable to each of the proposed Series of Subordinated Term Notes and Junior Subordinated Term Notes, having regard to the expected credit rating and tenor. Such solicitation of Indicative Spreads shall occur on the pricing date of the applicable Series of Subordinated Term Notes and Junior Subordinated Term Notes and may, at the FSM's option, also occur on other dates selected by the FSM provided that no such date is more than **one week** prior to the pricing date. The Applicable Spread for Subordinated Term Notes or Junior Subordinated Term Notes, as applicable, will be the simple average of the respective Indicative Spreads after excluding the highest and the lowest Indicative Spread for each day (not more than one week prior to the pricing date) that Indicative Spreads were provided;

(b) For Subordinated Warehouse Notes the FSM will solicit from time to time, but no less frequently than on an annual basis, from at least five investment dealers in Canada, a survey of Indicative Spreads over the applicable Base Rate applicable to commercial paper issuances having features comparable to the Subordinated Warehouse Notes including credit rating and tenor. The Applicable Spread for Subordinated Warehouse Notes will be the simple average of the respective Indicative Spreads, after excluding the highest and the lowest Indicative Spread;

(c) The Applicable Spread for Junior Subordinated Warehouse Notes shall be equal to the Applicable Spread derived from Section 2.04(b) for the Subordinated Warehouse Notes, provided the Junior Subordinated Term Notes are rated Investment Grade. If the Junior Subordinated Term Notes are rated below Investment Grade, the Applicable Spread for the Junior Subordinated Warehouse Notes will equal to the Applicable Spread for the Subordinated Warehouse Notes plus 100 bps.

For the purposes of this section "Investment Grade" means an "approved rating" from at least one "designated rating organization" (as such terms are defined for securities law purposes).

2.05 **Credit Ratings**

In order to facilitate the survey of Indicative Spreads, the FSM will solicit from time to time, from an approved rating organization (as such term is defined for securities laws

**Commented [TS(5]:** What does this mean on an objective basis?

**Commented [TS(6]:** Is OPG to keep a record of the underlying data to support the calculations (e.g., surveys etc.) and submit to the OFA/Ministry?

**Commented [TS(7]:** How do we know that these are the five best deals? Is there a risk that only fewer than 5 dealers in Canada with such offerings? If so, what is the alternative?

**Commented [TS(8]:** Five business days?

**Commented [TS(9]:** What is the methodology to determine comparables? Will each dealer have their own approach. Should these dealers have certain credentials etc.

purposes), a credit rating, which may include a shadow rating, for the Subordinated Notes and the Junior Subordinated Notes.

## ARTICLE 3 - GENERAL

### 3.01 Benefit of the Agreement

This Agreement will enure to the benefit of and be binding upon the respective successors and permitted assigns of the parties.

### 3.02 Entire Agreement

This Agreement constitutes the entire agreement between the parties with respect to the subject matter hereof and cancel and supersede any prior understandings and agreements between the parties with respect thereto. There are no representations, warranties, terms, conditions, undertakings or collateral agreements, express, implied or statutory, between the parties other than as expressly set forth in this Agreement.

### 3.03 Assignment, Amendments and Waivers

No assignment or amendment to this Agreement will be valid or binding unless set forth in writing and duly executed by all of the parties. No waiver of any breach of any provision of this Agreement will be effective or binding unless made in writing and signed by the party purporting to give the same and, unless otherwise provided in the written waiver, will be limited to the specific breach waived.

### 3.04 Severability

If any provision of this Agreement is determined to be invalid or unenforceable in whole or in part, such invalidity or unenforceability will attach only to such provision or part thereof and the remaining part of such provision and all other provisions hereof will continue in full force and effect.

### 3.05 Governing Law

This Agreement is governed by and will be construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein. For the purpose of all legal proceedings this Agreement will be deemed to have been performed in the Province of Ontario and the courts of the Province of Ontario will have exclusive jurisdiction to entertain any action arising under this Agreement. The parties hereby attorn to the exclusive jurisdiction of the courts of the Province of Ontario.

### 3.06 Counterparts

This Agreement may be executed in any number of counterparts, each of which will be deemed to be an original and all of which taken together will be deemed to constitute one and the same instrument.

3.07 **Electronic Execution**

Any party may deliver an executed signature page to this Agreement by electronic transmission and such delivery will be as effective as delivery of a manually executed copy of the Agreement by such party.

[SIGNATURE PAGES FOLLOW]

IN WITNESS WHEREOF the parties have executed this Agreement.

**ONTARIO POWER GENERATION INC.**
solely in its capacity as Financial Services Manager of the Fair Hydro Trust

Per: _____
Ken Hartwick
Chief Financial Officer and Senior Vice President

Per: _____
John Lee
Vice President- Treasurer

**HER MAJESTY THE QUEEN IN RIGHT OF ONTARIO**, as represented by the Minister of Energy

Per: _____
[Name]
[Position]

TORYS LLP

79 Wellington St. W., 30th Floor
Box 270, TD South Tower
Toronto, Ontario M5K 1N2 Canada
P. 416.865.0040 | F. 416.865.7380
www.torys.com

Brett Saulnier
bsaulnier@torys.com
P. 416.865.8148

February 8, 2018

**CONFIDENTIAL**

Ministry of Finance
7 Queen's Park Crescent, 7th Floor
Toronto, Ontario M7A 1Y7

**Attention**: Minister of Finance
Deputy Minister of Finance

Ministry of Energy
Hearst Block 4th Floor, 900 Bay Street
Toronto, Ontario M7A 2E1

**Attention:** Minister of Energy
Deputy Ministry of Energy

Dear Sirs/Mesdames:

**Re: Fair Hydro Plan – Deliveries under Change of Law Process Agreement**

Reference is made to the Change of Law Process Agreement dated as of December 21, 2017 between Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance, and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have their respective meanings in the Change of Law Process Agreement.

On February 9, 2018, Fair Hydro Trust (the "**Issuer**") will issue (i) C$500,000,000 aggregate principal amount of 3.357% Senior Notes due May 15, 2033, Series 2018-1 in accordance with the terms of an agency agreement dated as of February 6, 2018 among the Issuer, Ontario Power Generation Inc. ("**OPG**") and the dealers named therein, (ii) C$382,353,000 aggregate principal amount of 3.637% Subordinated Notes due May 15, 2033, Series 2018-1 and (iii) C$98,040,000 aggregate principal amount of 3.957% Junior Subordinated Notes due May 15, 2033, Series 2018-1 (collectively, the "**Funding Obligations**").

On behalf of Ontario Power Generation Inc. and pursuant to section 3.01 of the Change of Law Process Agreement, please find enclosed a Process Certificate in respect of the Funding Obligations.

On behalf of Ontario Power Generation Inc. and pursuant to section 2.01(c) of the Change of Law Process Agreement, please find enclosed one Special Payment Date Agreement in respect of each of the Warehouse Senior Series 2017-1 Supplemental Indenture dated as of December 21, 2017 among, *inter alios*, the Issuer, Royal Bank of Canada and BNY Trust Company of Canada (the "**Indenture Trustee**"), the Warehouse Subordinated Series 2017-1 Supplemental

Indenture dated as of December 21, 2017 among the Issuer, OPG and the Indenture Trustee and the Warehouse Junior Subordinated Series 2017-1 Supplemental Indenture dated as of December 21, 2017 among the Issuer, OPG and the Indenture Trustee (collectively, the "**Warehouse Facilities**"). Such Special Payment Date Agreements permit a partial repayment of the Warehouse Facilities using proceeds from the Funding Obligations on a date that is not the 15th day of a given calendar month and allow the decrease notice to be delivered within two business days of such repayment (rather than five business days).

Yours truly,



Brett Saulnier

Encl.

cc: Rima Ramchandani, *Torys LLP*
John Lee, *Ontario Power Generation Inc.*
Lubna Ladak, *Ontario Power Generation Inc.*
Leslie Wong, *Ontario Power Generation Inc.*

24966160.1

**ONTARIO POWER GENERATION INC.,**
**in its capacity as FSM**

# PROCESS CERTIFICATE

*Certificate of the CFO and Treasurer pursuant to section 3.01 of the Change of Law Process Agreement*

**TO:** Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance (the "**Province**")

**RE:** C$500,000,000 aggregate principal amount of 3.357% Senior Notes due May 15, 2033, Series 2018-1 (the "**Series 2018-1 Senior Notes**")

**AND RE:** C$382,353,000 aggregate principal amount of 3.637% Subordinated Notes due May 15, 2033, Series 2018-1 (the "**Series 2018-1 Subordinated Notes**")

**AND RE:** C$98,040,000 aggregate principal amount of 3.957% Junior Subordinated Notes due May 15, 2033, Series 2018-1 (the "**Series 2018-1 Junior Subordinated Notes**")

**AND RE:** Agency agreement between Fair Hydro Trust (the "**Issuer**"), Ontario Power Generation Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., Goldman Sachs Canada Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc., TD Securities Inc., Morgan Stanley Canada Limited, HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., Desjardins Securities Inc. and Casgrain & Company Limited dated as of February 6, 2018 (the "**Agency Agreement**" and together with the Series 2018-1 Senior Notes, the Series 2018-1 Subordinated Notes and the Series 2018-1 Junior Subordinated Notes, the "**Funding Obligations**")

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Reference is made to the Change of Law Process Agreement dated December 21, 2017 among the Province and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have the meanings ascribed to such terms in the Change of Law Process Agreement.

Each of the undersigned, being the Chief Financial Officer and Treasurer of OPG acting in its capacity as FSM and holding the offices set forth under their names and signatures below, pursuant to and accordance with section 3.01 of the Change of Law Process Agreement, hereby certifies for and on behalf of OPG, in its capacity as Financial Services Manager, and not in such officer's personal capacity and intending that this certificate may be relied on by the addressees hereof without independent inquiry, that:

1. I have read and understand the provisions of the Change of Law Process Agreement and all other documents and materials necessary to enable me to deliver this certificate.

2. The material terms of the Series 2018-1 Senior Notes are set forth in Schedule A.

3. The material terms of the Series 2018-1 Subordinated Notes are set forth in Schedule B.

4. The material terms of the Series 2018-1 Junior Subordinated Notes are set forth in Schedule C.

5. The material terms of the Agency Agreement are set forth in Schedule D.

6. The Funding Obligations:

   (a) will arise under terms and conditions that are Substantially in the Form of the Reference Documentation applicable thereto;

   (b) in my opinion, are reasonably incurred or effected in compliance with the Act, the General Regulation, any other enactments related thereto and the Financing Plan;

   (c) are of a type and are on terms that a reasonably prudent financial services manager would incur in similar circumstances; and

   (d) reflect, in all material respects, arm's length terms and conditions.

7. The Disclosure Document used in connection with the offering and sale of the Series 2018-1 Senior Notes is Substantially in the Form of the Reference Documentation. No Disclosure Document was used in connection with the offering and sale of the Series 2018-1 Subordinated Notes or Series 2018-1 Junior Subordinated Notes.

8. Any disclosure made in respect of any of the Funding Obligations (including any Disclosure Document, press release or other written communication prepared for dissemination to third parties in relation to any of the Funding Obligations) that refers to or describes the terms, effect or adherence of or to the Change of Law Process Agreement or the Change of Law Protection Agreement has been made available to the Province prior to use or dissemination, other than where such disclosure was substantially the same as a disclosure previously made.

9. No Breach Event has occurred on or prior to the date hereof, unless such Breach Event has been waived by the Province in writing.

10. At the time the Funding Obligations are incurred, the maximum aggregate payment amounts due or becoming due in the future in respect of Repayments under the Funding Obligations, together with all other outstanding amounts due or becoming due in the future in respect of Repayments under all Approved Obligations, do not exceed the Protection Agreement Maximum applicable on the date hereof.

***[Remainder of page intentionally left blank.]***

**DATED** as of the 9th day of February, 2018.

Name: Ken Hartwick
Title: Chief Financial Officer and
Senior Vice President

Name: John Lee
Title: Vice President – Treasurer

*[Signature page to Process Certificate]*

# SCHEDULE A

| SERIES 2018-1 SENIOR NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$500,000,000 |
| Interest Rate | 3.357% per annum (the "**Series 2018-1 Senior Interest Rate**") |
| Interest Payments | The "**Interest Payment Dates**" for the Series 2018-1 Senior Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-1 Senior Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-1 Senior Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "**MTI**")) thereafter at a rate equal to the monthly equivalent of the Series 2018-1 Senior Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-1 Senior Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-1 Senior Notes will include accrued and unpaid interest for the period from, and including, February 9, 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$8.73739726 per C$1,000 principal amount of Series 2018-1 Senior Notes.<br><br>"**Amortization Event**" means either an Acceleration Event has occurred with respect to the Series 2018-1 Senior Notes, or the outstanding principal amount of the Series 2018-1 Senior Notes has not been paid in full on May 15, 2033.<br><br>"**Acceleration Event**" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-1 Senior Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000.03 per C$1,000 principal amount of Series 2018-1 Senior Notes |
| Fees | See Schedule D under the heading "Fees" |
| Term to Maturity | 15.25 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-1 Senior Notes shall be due and payable on May 15, 2033. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-1 Senior Notes and the then outstanding principal amount of the Series 2018-1 Senior Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2033 for the Series 2018-1 Senior Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-1 Senior Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-1 Senior Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-1 Senior Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix 1 hereto. |
| Extension | N/A |
| Redemption | The Series 2018-1 Senior Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-1 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"**Par Call Date**" means November 15, 2032.<br><br>"**Series 2018-1 Canada Yield Price**" means a price equal to the price of the Series 2018-1 Senior Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.23% per annum.<br><br>"**Government of Canada Yield**" on any date means, in respect of the Series 2018-1 Senior Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 1

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| January 15, 2030 | C$3,655,755.29 |
| February 15, 2030 | C$7,626,564.99 |
| March 15, 2030 | C$8,257,633.61 |
| April 15, 2030 | C$8,191,586.84 |
| May 15, 2030 | C$7,890,462.63 |
| June 15, 2030 | C$7,584,364.60 |
| July 15, 2030 | C$9,084,874.20 |
| August 15, 2030 | C$11,442,279.18 |
| September 15, 2030 | C$12,391,444.77 |
| October 15, 2030 | C$12,750,308.92 |
| November 15, 2030 | C$11,982,236.88 |
| December 15, 2030 | C$11,293,079.64 |
| January 15, 2031 | C$10,793,983.66 |
| February 15, 2031 | C$10,722,332.46 |
| March 15, 2031 | C$11,500,665.58 |
| April 15, 2031 | C$11,354,192.22 |
| May 15, 2031 | C$10,817,597.00 |
| June 15, 2031 | C$10,295,734.83 |
| July 15, 2031 | C$9,657,558.16 |
| August 15, 2031 | C$9,972,812.07 |
| September 15, 2031 | C$10,763,812.68 |
| October 15, 2031 | C$11,008,621.17 |
| November 15, 2031 | C$10,283,044.04 |
| December 15, 2031 | C$9,663,858.15 |
| January 15, 2032 | C$11,614,637.47 |
| February 15, 2032 | C$14,086,300.93 |
| March 15, 2032 | C$15,155,597.37 |
| April 15, 2032 | C$15,258,171.67 |
| May 15, 2032 | C$14,584,770.10 |
| June 15, 2032 | C$13,686,506.16 |
| July 15, 2032 | C$14,172,728.13 |
| August 15, 2032 | C$16,021,396.29 |
| September 15, 2032 | C$17,345,995.76 |
| October 15, 2032 | C$17,773,273.46 |
| November 15, 2032 | C$16,598,773.70 |
| December 15, 2032 | C$15,634,984.01 |
| January 15, 2033 | C$16,715,366.47 |
| February 15, 2033 | C$18,464,628.87 |
| March 15, 2033 | C$19,935,085.13 |
| April 15, 2033 | C$19,792,624.35 |
| May 15, 2033 | C$4,174,356.56 |

# SCHEDULE B

| SERIES 2018-1 SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$382,353,000 |
| Interest Rate | 3.637% per annum (the "**Series 2018-1 Subordinated Interest Rate**") |
| Interest Payments | The "**Interest Payment Dates**" for the Series 2018-1 Subordinated Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-1 Subordinated Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-1 Subordinated Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "**MTI**")) thereafter at a rate equal to the monthly equivalent of the Series 2018-1 Subordinated Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-1 Subordinated Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-1 Subordinated Notes will include accrued and unpaid interest for the period from, and including, February 9, 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$9.466164384 per C$1,000 principal amount of Series 2018-1 Subordinated Notes.<br><br>"**Amortization Event**" means either an Acceleration Event has occurred with respect to the Series 2018-1 Subordinated Notes, or the outstanding principal amount of the Series 2018-1 Subordinated Notes has not been paid in full on May 15, 2033.<br><br>"**Acceleration Event**" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-1 Subordinated Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000 per C$1,000 principal amount of Series 2018-1 Subordinated Notes |
| Fees | N/A |
| Term to Maturity | 15.25 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-1 Subordinated Notes shall be due and payable on May 15, 2033. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-1 Subordinated Notes and the then outstanding principal amount of the Series 2018-1 Subordinated Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2033 for the Series 2018-1 Subordinated Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-1 Subordinated Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-1 Subordinated Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-1 Subordinated Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix 2 hereto. |
| Extension | N/A |
| Redemption | The Series 2018-1 Subordinated Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-1 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"**Par Call Date**" means November 15, 2032.<br><br>"**Series 2018-1 Canada Yield Price**" means a price equal to the price of the Series 2018-1 Subordinated Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.30% per annum.<br><br>"**Government of Canada Yield**" on any date means, in respect of the Series 2018-1 Subordinated Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 2

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| January 15, 2030 | C$2,795,577.57 |
| February 15, 2030 | C$5,832,079.11 |
| March 15, 2030 | C$6,314,661.00 |
| April 15, 2030 | C$6,264,154.64 |
| May 15, 2030 | C$6,033,883.19 |
| June 15, 2030 | C$5,799,808.22 |
| July 15, 2030 | C$6,947,256.74 |
| August 15, 2030 | C$8,749,978.20 |
| September 15, 2030 | C$9,475,810.71 |
| October 15, 2030 | C$9,750,236.23 |
| November 15, 2030 | C$9,162,887.03 |
| December 15, 2030 | C$8,635,884.43 |
| January 15, 2031 | C$8,254,222.80 |
| February 15, 2031 | C$8,199,430.70 |
| March 15, 2031 | C$8,794,626.62 |
| April 15, 2031 | C$8,682,617.58 |
| May 15, 2031 | C$8,272,280.06 |
| June 15, 2031 | C$7,873,208.99 |
| July 15, 2031 | C$7,385,191.53 |
| August 15, 2031 | C$7,626,268.05 |
| September 15, 2031 | C$8,231,150.87 |
| October 15, 2031 | C$8,418,357.37 |
| November 15, 2031 | C$7,863,504.27 |
| December 15, 2031 | C$7,390,009.17 |
| January 15, 2032 | C$8,881,781.59 |
| February 15, 2032 | C$10,771,877.18 |
| March 15, 2032 | C$11,589,574.46 |
| April 15, 2032 | C$11,668,013.63 |
| May 15, 2032 | C$11,153,059.49 |
| June 15, 2032 | C$10,466,151.77 |
| July 15, 2032 | C$10,837,968.57 |
| August 15, 2032 | C$12,251,655.99 |
| September 15, 2032 | C$13,264,584.99 |
| October 15, 2032 | C$13,591,326.76 |
| November 15, 2032 | C$12,693,179.89 |
| December 15, 2032 | C$11,956,164.24 |
| January 15, 2033 | C$12,782,339.07 |
| February 15, 2033 | C$14,120,010.31 |
| March 15, 2033 | C$15,244,476.86 |
| April 15, 2033 | C$15,135,536.27 |
| May 15, 2033 | C$3,192,213.85 |

# SCHEDULE C

| SERIES 2018-1 JUNIOR SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$98,040,000 |
| Interest Rate | 3.957% per annum (the "**Series 2018-1 Junior Subordinated Interest Rate**") |
| Interest Payments | The "**Interest Payment Dates**" for the Series 2018-1 Junior Subordinated Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-1 Junior Subordinated Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-1 Junior Subordinated Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "**MTI**")) thereafter at a rate equal to the monthly equivalent of the Series 2018-1 Junior Subordinated Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-1 Junior Subordinated Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-1 Junior Subordinated Notes will include accrued and unpaid interest for the period from, and including, February 9, 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$10.299041096 per C$1,000 principal amount of Series 2018-1 Junior Subordinated Notes.<br><br>"**Amortization Event**" means either an Acceleration Event has occurred with respect to the Series 2018-1 Junior Subordinated Notes, or the outstanding principal amount of the Series 2018-1 Junior Subordinated Notes has not been paid in full on May 15, 2033.<br><br>"**Acceleration Event**" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-1 Junior Subordinated Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000 per C$1,000 principal amount of Series 2018-1 Junior Subordinated Notes |
| Fees | N/A |
| Term to Maturity | 15.25 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-1 Junior Subordinated Notes shall be due and payable on May 15, 2033. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-1 Junior Subordinated Notes and the then outstanding principal amount of the Series 2018-1 Junior Subordinated Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2033 for the Series 2018-1 Junior Subordinated Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-1 Junior Subordinated Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-1 Junior Subordinated Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-1 Junior Subordinated Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix 3 hereto. |
| Extension | N/A |
| Redemption | The Series 2018-1 Junior Subordinated Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-1 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"**Par Call Date**" means November 15, 2032.<br><br>"**Series 2018-1 Canada Yield Price**" means a price equal to the price of the Series 2018-1 Junior Subordinated Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.38% per annum.<br><br>"**Government of Canada Yield**" on any date means, in respect of the Series 2018-1 Junior Subordinated Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 3

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| January 15, 2030 | C$716,814.76 |
| February 15, 2030 | C$1,495,404.90 |
| March 15, 2030 | C$1,619,143.85 |
| April 15, 2030 | C$1,606,193.50 |
| May 15, 2030 | C$1,547,149.54 |
| June 15, 2030 | C$1,487,130.31 |
| July 15, 2030 | C$1,781,347.88 |
| August 15, 2030 | C$2,243,584.15 |
| September 15, 2030 | C$2,429,695.05 |
| October 15, 2030 | C$2,500,060.57 |
| November 15, 2030 | C$2,349,458.21 |
| December 15, 2030 | C$2,214,329.34 |
| January 15, 2031 | C$2,116,467.38 |
| February 15, 2031 | C$2,102,418.13 |
| March 15, 2031 | C$2,255,032.47 |
| April 15, 2031 | C$2,226,312.20 |
| May 15, 2031 | C$2,121,097.45 |
| June 15, 2031 | C$2,018,771.54 |
| July 15, 2031 | C$1,893,638.85 |
| August 15, 2031 | C$1,955,453.35 |
| September 15, 2031 | C$2,110,551.51 |
| October 15, 2031 | C$2,158,553.17 |
| November 15, 2031 | C$2,016,283.15 |
| December 15, 2031 | C$1,894,874.15 |
| January 15, 2032 | C$2,277,379.90 |
| February 15, 2032 | C$2,762,019.79 |
| March 15, 2032 | C$2,971,685.76 |
| April 15, 2032 | C$2,991,798.37 |
| May 15, 2032 | C$2,859,758.84 |
| June 15, 2032 | C$2,683,628.66 |
| July 15, 2032 | C$2,778,966.30 |
| August 15, 2032 | C$3,141,450.25 |
| September 15, 2032 | C$3,401,175.64 |
| October 15, 2032 | C$3,484,955.58 |
| November 15, 2032 | C$3,254,661.51 |
| December 15, 2032 | C$3,065,683.14 |
| January 15, 2033 | C$3,277,522.84 |
| February 15, 2033 | C$3,620,515.46 |
| March 15, 2033 | C$3,908,840.22 |
| April 15, 2033 | C$3,880,906.74 |
| May 15, 2033 | C$819,285.59 |

# SCHEDULE D

| AGENCY AGREEMENT TERMS | |
|---|---|
| Appointment | The Issuer appoints the Agents to act as its sole and exclusive agents to effect the solicitation and private placement of Series 2018-1 Senior Notes to "accredited investors", as such term is defined under applicable securities laws, in the Provinces of Canada (the "**Offering**"). |
| Fees | In consideration of the services provided to the Issuer by the Agents, the Issuer agrees to pay the Agents a fee equal to 0.50% of the aggregate principal amount of Series 2018-1 Senior Notes sold in the Offering. |
| Representations and Warranties | Representations and warranties in favour of the Agents from each of the Issuer and OPG customary for a private placement of notes, including representations that the disclosure document used in connection with the Offering does not contain a "misrepresentation", as such term is defined under applicable securities laws. |
| Conditions to Closing | As conditions to the closing of the Offering, the Issuer must provide, or arrange to have provided, certain standard certificates, legal opinions and other deliverables to the Agents. |
| Termination | The Agents have customary rights to terminate their obligations on the occurrence of certain events, including legal or other proceedings resulting in a material adverse change, a material adverse change in respect of the Issuer and financial disasters. |
| Indemnity | Each of the Issuer and OPG provides an indemnity to each of the Agents for any losses resulting from, among other things, breaches of representations, warranties and covenants, breaches of securities laws or a "misrepresentation" in the disclosure document used in connection with the Offering. |

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT
## (Senior Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Senior Series 2017-1 Supplemental Indenture (the "**Senior Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about February 9, 2018 of Senior Notes bearing the full designation "3.357% Senior Notes due May 15, 2033, Series 2018-1" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Senior Warehouse Supplemental Indenture, the date of issuance of the Senior Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Senior Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $500,000,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Senior Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Senior Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Senior Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4(a) of the Senior Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Senior Notes. If the Special Principal Payment Date has not

occurred by February 28, 2018 this Special Principal Payment Date Agreement shall cease of be of any force and effect.

7. Except as modified hereby, the provisions of the Senior Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Each Series 2017-1 Senior Noteholder acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

***[Signature Page Follows]***

**DATED** this 7th day of February, 2018.

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **FAIR HYDRO TRUST**, as Issuer

By: **ONTARIO POWER GENERATION INC.**, not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

**BNY TRUST COMPANY OF CANADA**, as
Indenture Trustee

By: _____
Name: Ahmad Adam
Title: Vice-President

**ROYAL BANK OF CANADA**, as Administrative Agent

**Ca**

By: _____
Name: Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: Nur Khan
Authorized Signatory

**CIBC MELLON TRUST COMPANY**, in its capacity as trustee of **LAKESHORE TRUST**, by its Financial Services Agent, **ROYAL BANK OF CANADA**, as a CP Conduit Purchaser

By: _____
Name Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: Nur Khan
Authorized Signatory

**ROYAL BANK OF CANADA**, as a Group Bank

By: _____
Name: Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: Nur Khan
Authorized Signatory

**CANADIAN IMPERIAL BANK OF COMMERCE**, as a Group Bank

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **SOUND TRUST**, by its Financial Services Agent, **CANADIAN IMPERIAL BANK OF COMMERCE**, as a CP Conduit Purchaser

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **SURE TRUST**, by its Financial Services Agent, **CANADIAN IMPERIAL BANK OF COMMERCE**, as a CP Conduit Purchaser

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

**GOLDMAN SACHS CANADA INC.**

By: _____
Name: JASON ROWE
Title: Managing Director

*[Signature page to Global Direction and Receipt]*

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT
## (Subordinated Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Subordinated Series 2017-1 Supplemental Indenture (the "**Subordinated Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about February 9, 2018 of Subordinated Notes bearing the full designation "3.637% Subordinated Notes due May 15, 2033, Series 2018-1" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Subordinated Warehouse Supplemental Indenture, the date of issuance of the Subordinated Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Subordinated Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $382,353,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Subordinated Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Subordinated Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Subordinated Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4 of the Subordinated Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Subordinated Notes. If the Special Principal Payment Date has not occurred by February 28, 2018 this Special Principal Payment Date Agreement shall cease of be of any force and effect.

7. Except as modified hereby, the provisions of the Subordinated Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Ontario Power Generation Inc. acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

***[Signature Page Follows]***

**DATED** this 7th day of February, 2018.

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **FAIR HYDRO TRUST**, as Issuer

By: **ONTARIO POWER GENERATION INC.**, not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

**BNY TRUST COMPANY OF CANADA**, as
Indenture Trustee

By: _____
Name: Ahmad Adam
Title: Vice-President

*[Signature page to Special Principal Payment Date Agreement – Subordinated Warehouse]*

**ONTARIO POWER GENERATION INC.**

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and
Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT
## (Junior Subordinated Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Junior Subordinated Series 2017-1 Supplemental Indenture (the "**Junior Subordinated Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about February 9, 2018 of Junior Subordinated Notes bearing the full designation "3.957% Junior Subordinated Notes due May 15, 2033, Series 2018-1" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Junior Subordinated Warehouse Supplemental Indenture, the date of issuance of the Junior Subordinated Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Junior Subordinated Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $98,040,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Junior Subordinated Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Junior Subordinated Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Junior Subordinated Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4 of the Junior Subordinated Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Junior Subordinated Notes. If the Special Principal Payment Date has not occurred by February 28, 2018 this Special Principal Payment Date Agreement shall cease of be of any force and effect.

7. Except as modified hereby, the provisions of the Junior Subordinated Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Ontario Power Generation Inc. acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

***[Signature Page Follows]***

**DATED** this 7th day of February, 2018.

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **FAIR HYDRO TRUST**, as Issuer

By: **ONTARIO POWER GENERATION INC.**, not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

**BNY TRUST COMPANY OF CANADA**, as
Indenture Trustee

By: _____
Name: Ahmad Adam
Title: Vice-President

**ONTARIO POWER GENERATION INC.**

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and
Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

# OPG 2017-2019 Business Plan

*Ministry of Energy Clarification Questions – OPG Responses Set 1*

**OPG responses have been inserted in blue typeface, after each question. Numbers may not add due to rounding.**

1. What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast?

| OPG 2015-17 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 471 | 586 | 673 |
| Income Taxes | 224 | 159 | 182 |
| **Earnings Before Tax** | **695** | **745** | **855** |

| OPG 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 302 | 694 | 686 |
| Income Taxes | 104 | 245 | 155 |
| **Earnings Before Tax** | **406** | **939** | **841** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | 349 | 702 | 678 | 726 |
| **Income Tax PILs** | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **445** | **868** | **813** | **896** |

2. Can you provide the breakdown of GRC, Proxy Property Tax, and Ontario Capital Tax for fiscal years 2016-2020 based on OPG's 2017-19 business plan?

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **GRC: Payable to OEFC** | | | | |
| **GRC: Payable to NPC** | | | | |
| **Property Tax Payable to OEFC** | 15 | 18 | 19 | 19 |
| **Total** | **336** | **350** | **363** | **362** |
| | | | | |
| **Income Tax [This section is intended to gain insight into the current vs. future taxes, as well as taxes for regulatory purposes.]** | | | | |
| **Current Income Tax Payable** | | | | |
| **Increase/(Decrease) in Future Income Tax Liability** | | | | |
| **Income Taxes Payable to Ratepayers** | | | | |
| **Total** | **96** | **166** | **135** | **170** |

**The table below contains the information requested.**

| | Province's March 31 Fiscal Year | | | | |
|---|---|---|---|---|---|
| | Forecast (October 2016) | Forecast (Current) | 2017-2019 BP | | |
| *$ millions* | 2017 | 2017 | 2018 | 2019 | 2020 |
| **Net Income Before Extraordinary Gain Attributable to Shareholder** | **349** | **379** | **702** | **678** | **726** |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 314 | 307 | 325 | 337 | 335 |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 7 | 8 |
| Property Tax Payable to OEFC | 15 | 14 | 18 | 19 | 19 |
| **Total** | **336** | **329** | **350** | **363** | **362** |
| **Income Tax** | | | | | |
| Current Income Tax Payable | 119 | 86 | 109 | 85 | 133 |
| Increase/(Decrease) in Future Income Tax Liability | (39) | 2 | 106 | 123 | 92 |
| Income Taxes Payable to Ratepayers | 15 | 3 | (48) | (73) | (55) |
| **Income Tax PILs** | 96 | 92 | 166 | 135 | 170 |
| **Total Shareholder Return** | **781** | **800** | **1,218** | **1,176** | **1,258** |

3. In addition, could you provide a financial summary of the OPG head office sale (i.e. pre-tax gain of $296)? What is the PIL expense without this headquarter sales gain?

**Below is the financial impact of the gain on the sale of OPG's head office property that is included in the Province's fiscal year ended March 31, 2018:**

Financial Impact of gain on sale of OPG's head office property

| $ millions | **2018*** |
|---|---|
| Earnings Before Tax (EBT) | |
| Assumed Proceeds | 400 |
| Assumed Net Book Value | (104) |
| EBT- Other Income | 296 |
| Income Tax Expense | 74 |
| **Net Income Impact** | **223** |

*Province's fiscal year ended March 31, 2018

**In early January 2017, subsequent to the approval of the 2017-2019 BP, OPG reached an agreement with KingSett Canadian Real Estate Income Fund LP for the purchase of OPG's head office property. The transaction is scheduled to close in early April 2017. The pre-tax gross proceeds before closing costs are expected to be $508 M, with a distribution to the Trillium Trust estimated at $285 M.**

- Is there a PILs element related to the headquarter sale in the $166M PIL number provided? [Essentially, we would like OPG's insight on the allocation of $296M to PILs vs. Net Income].

  **See table in previous response.**

- Could we also confirm that $296M is the amount built into the 2017-19 BP forecast for 2017-18?

  **Confirmed.**

- The 2017-19 BP mentions that a gain on sale of OPG's head office is expected in 2017, "net of new leaseback costs and foregone lease income". Could you please provide how much of the $296 is the leaseback/foregone lease income costs for 2017 and also provide a forecast for the remaining years in the BP (up to 2019).

  **The comment that a "gain on sale of OPG's head office is expected in 2017, net of new leaseback costs and foregone lease income" was in the context of overall Net Income changes in 2017 vs 2016. This comment was meant to indicate that the foregone revenue and higher leasback costs were a year over year reduction in income.The $296M Pre-tax gain does not include this impact. The approximate annual impacts of forgone lease revenue and higher leaseback costs from the sale of OPG's head office property assumed in the 2017-2019 BP are as follows:**

| Favorarable/(unfavorable)- $ millions | 2017* | 2018 | 2019 |
|---|---|---|---|
| Forgone net revenue | (22) | (29) | (29) |
| Leaseback costs | (7) | (9) | (9) |
| Elimination of other costs | 12 | 16 | 16 |
| Forgone Earnings Before Tax (EBT) | (17) | (22) | (22) |

*Sale assumed to occur in April 2017

4. Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "OEB's decision on OPG's rate application is expected during the third quarter of 2017." Is it your current outlook that OEB's decision would still be retroactive to January 1, 2017?

5. Could you provide the financing requirements for the Darlington Refurbishment Project separately from other borrowing requirements?

6. Page 1-2 or Appendix 3:
   a) The March 31, 2017 Fiscal Net Income Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.
   b) Page 1 shows the 2016 Forecast of NI Attributable to Shareholder to be $438M. This is Jan 1, 2016 to Dec 31, 2016.
   c) We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?

7. In the past, OPG had a provision of approximately $200 million in their forecast model that was provided. Could you confirm if this provision is included in the current BP numbers? Similarly in the past, could you also provide the forecast model?

8. Can you provide a more detailed financing and liquidity outlook, specifically the operating cash flow section of the cash flow statement, to explain the drivers behind the ~$1B reduction in operating cash flow in 2017, as well as changes throughout 2016-2021? This is in order to reconcile the $1.2B change in net operating cash flow for 2017 from 2016 ($2.739B in 2016 to $1.531B in 2017). The BP states this is due to lower production, a foregone rate rider, and accrual of new rates in net income; however, the movements in the financial statements (i.e., income accounts and B/S operating account movements) are significantly lower than the $1.2B amount.

# OEFC BOARD OF DIRECTORS MEETING

September 28, 2018 @ 2:30 PM – 4:00 PM
Trillium Boardroom - Frost Building South, 7th Floor

**Call in: (local) 416-212-8011; (long distance) 866-602-5461; (Conference ID) 2218108#**

## A G E N D A

| INTRODUCTORY ITEMS | TAB |
|---|---|

1. Call to Order (Chair)
2. Review of Agenda and Confirmation of Receipt of Meeting Material (Chair)
3. Declaration of Possible Conflicts (Chair)
4. Chair's Remarks (Chair)
5. CEO's Report (Gadi Mayman)
   - Status of OEFC borrowing
   - Current issues or concerns
   - Recently approved Minister's Directives
   - Compliance with directives
6. Educational Intiatives (Chair)

**DECISIONS ITEMS**

7. Approval and Signing: Minutes of Meeting held on July 20, 2018 (Mara Collins) ..... **8**

**Report from the Audit Committee and Approval of Recommended Items**

8. Audit Committee Chair's Report (Chair)
9. Approval: OEFC Financial Statements for the Period ended June 30, 2018 (Ken Kandeepan) ..... **9**
10. Approval: OEFC Risk Management Reporting Policy (Murray Lindo, Ken Kandeepan) ..... **10**
11. Approval: OEFC Memorandum of Understanding (Sarah Neville) ..... **11**

**DISCUSSION ITEMS**

**Reports Reviewed by Audit Committee**

12. Quarterly Report on OPG Funding and Liquidity (John Kim, Mike Manning) ..... **12**
13. Quarterly Program Status, Exposures and Results Report (Ken Kandeepan) ..... **13**
14. Quarterly Litigation Summary (Kenneth Russell)
15. Quarterly OEFC Procurement Report (Mara Collins)

**Other Reports**

16. List of Action Items (no outstanding items from previous minutes) (Mara Collins)
17. NUG Report (Emily Kerr) ..... **17**
18. Quarterly Business Plan status report (Gadi Mayman) ..... **18**

19. Legal Compliance Report (Mara Collins)

**Administrative Items**

20. Future Agenda Items
21. Other Business
22. Termination

**NEXT MEETING DATE: DECEMBER 14, 2018 @ 2:30 PM**

**OEFC BOARD OF DIRECTORS**

Greg Orencsak, Chair
Gadi Mayman, Vice-Chair
Denise Dwyer
Nancy Kennedy
Ronald Kwan
John Lieou
Murray Lindo
Maria Mavroyannis
Kaili Sermat-Harding
Sriram Subrahmanyan
Cindy Veinot

OEFC BOARD SECRETARY

Mara Collins - Legal Counsel

**INVITEES**

OFA STAFF

Ken Kandeepan - Chief Financial & Risk Officer
Emily Kerr - Director (A), Strategic Project Finance Branch
John Kim - Director, Electricity Finance Branch
Mike Manning - Executive Director & Chief Investment Officer
Sarah Neville - Legal Director
Caroline Swerdlyk - Legal Counsel

INDEPENDENT INVITEE

Kenneth Russell - Lawyer

| | |
|---|---|
| Equity Injection | 44% |
| Assumed Interest Cost | 4.5% |

**Biennial**

| **$ nominal million** | **2017-Jul** | **2017-Nov** | **2018-May** |
|---|---|---|---|
| | 2017 | 2017 | 2018 |
| | Jul | Nov | May |
| | 7 | 11 | 5 |
| **First Date** | 42917 | 43040 | 43221 |
| | | 43039 | 43220 |
| Fair Allocation Amount | -931 | -779 | -629 |
| Readjustment amount | -74 | -341 | -470 |
| Total borrowing requirement including financing costs | -1005 | -1120 | -1099 |

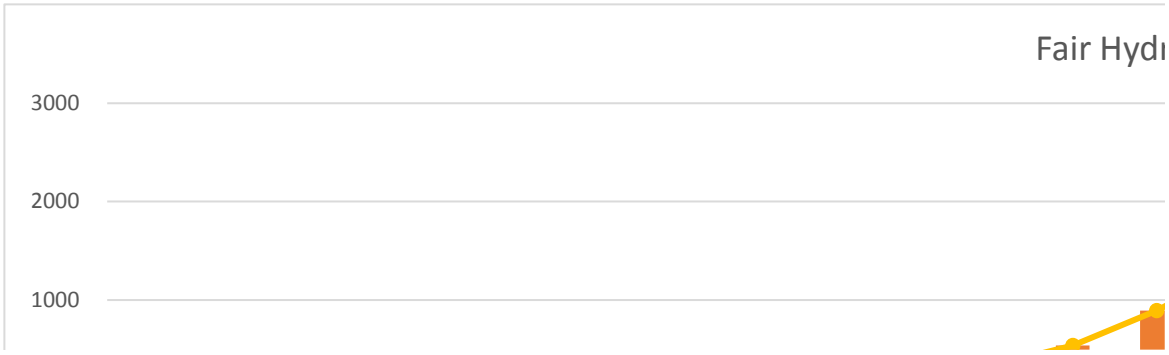
**Annual**

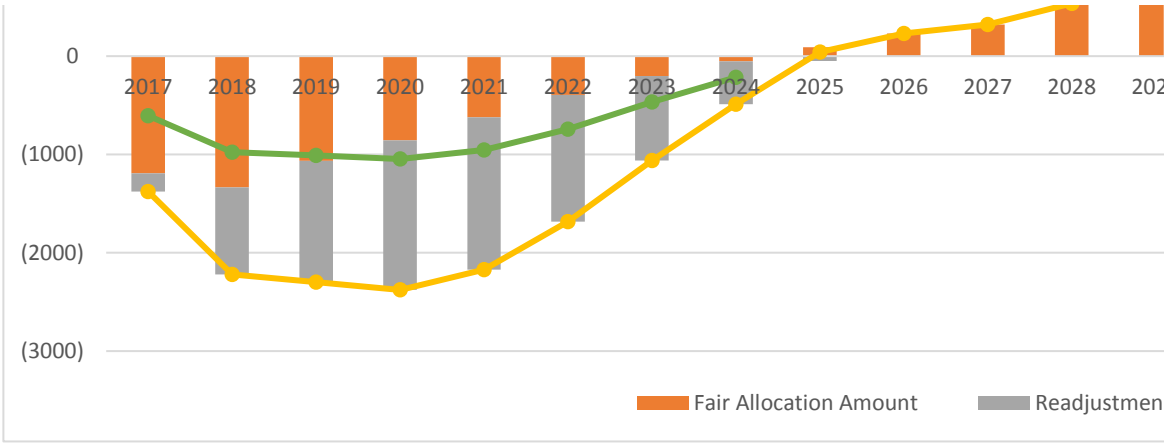
| **$ nominal million** | **2017** | **2018** | **2019** |
|---|---|---|---|
| Fair Allocation Amount | (1191) | (1336) | (1064) |
| Readjustment amount | (188) | (885) | (1233) |
| Total Annual Borrowing Requirement | (1378) | (2221) | (2297) |
| Accumulated borrowing requirement including financing costs | | (3599) | (5896) |
| OPG Equity Injection (44%) | (606) | (977) | (1011) |

*This includes financing costs, which may need to be excluded upon further information available

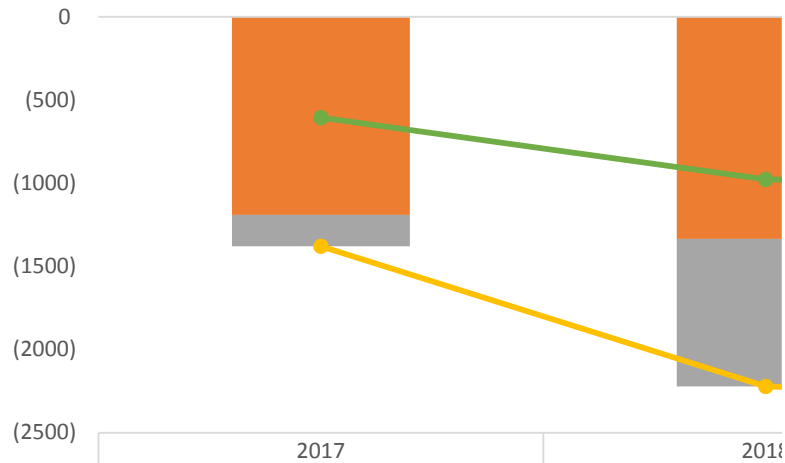
**Fiscalized**

| **$ nominal million** | **2017-18** | **2018-19** | **2019-20** |
|---|---|---|---|
| Fair Allocation Amount | (1580) | (1227) | (1014) |
| Readjustment amount | (358) | (997) | (1312) |
| Total Borrowing Requirement | (1938) | (2224) | (2326) |
| Accumulated borrowing requirement including financing costs | | (4162) | (6488) |
| OPG Equity Injection (44%) | (853) | (979) | (1023) |





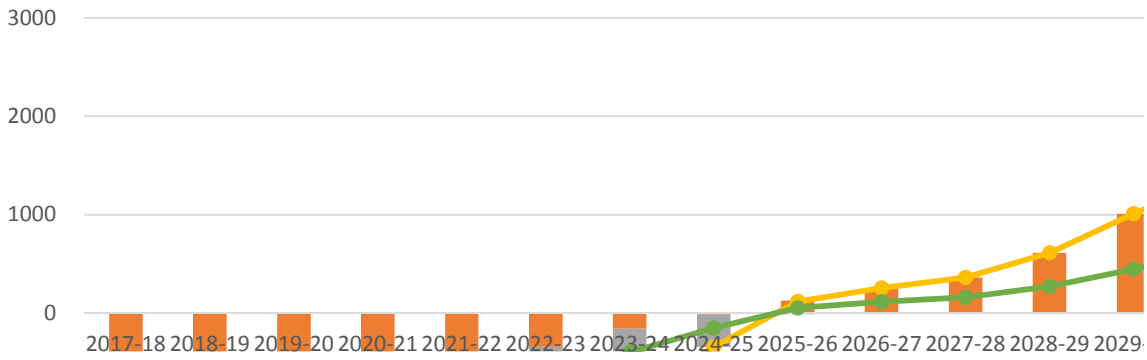

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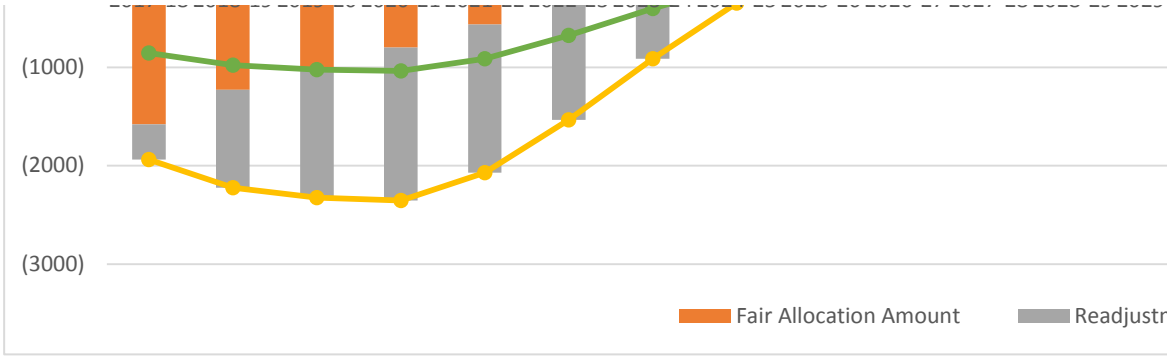


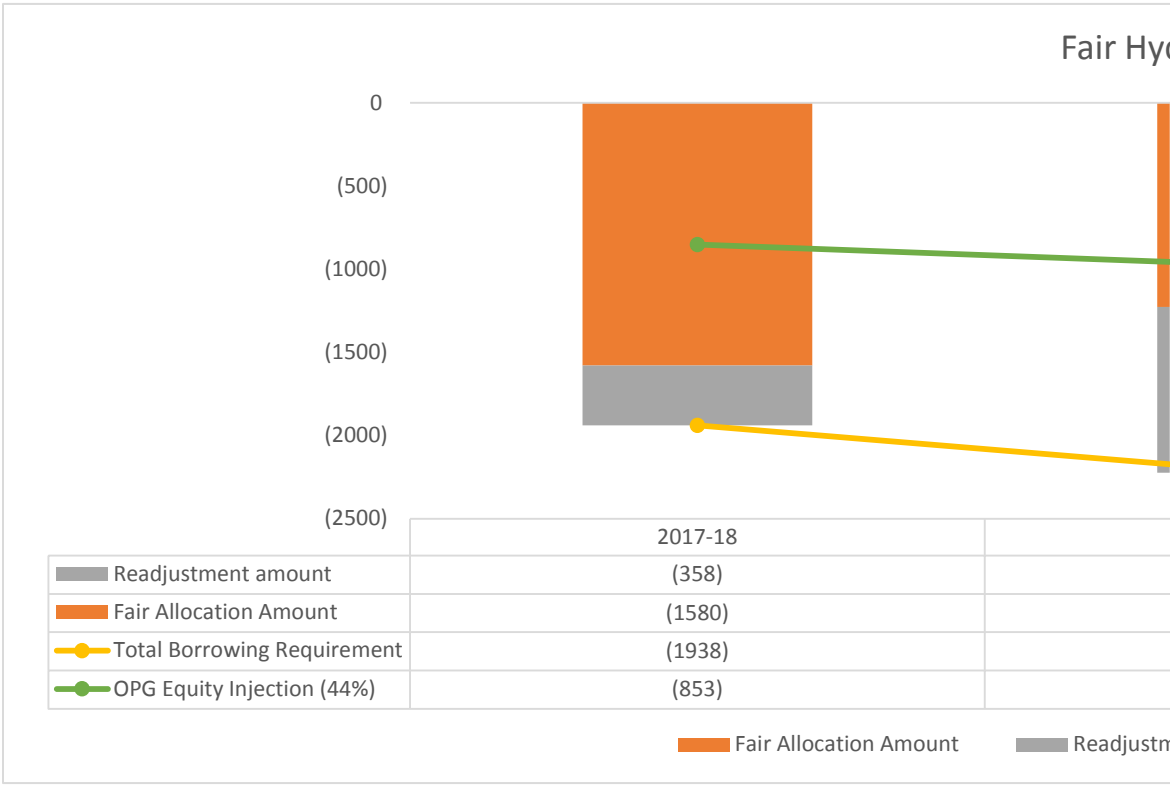

| | 2017 | 2018 |
|---|---|---|
| Readjustment amount | (188) | (885 |
| Fair Allocation Amount | (1191) | (133( |
| Total Annual Borrowing Requirement | (1378) | (222 |
| OPG Equity Injection (44%) | (606) | (977 |

Fair Allocation Amount  Readjustment

Fair Hy




(1000)
(2000)
(3000)
Fair Allocation Amount
Readjustr


Fair Hy
0
(500)
(1000)
(1500)
(2000)
(2500)
2017-18
Readjustment amount (358)
Fair Allocation Amount (1580)
Total Borrowing Requirement (1938)
OPG Equity Injection (44%) (853)
Fair Allocation Amount
Readjustm

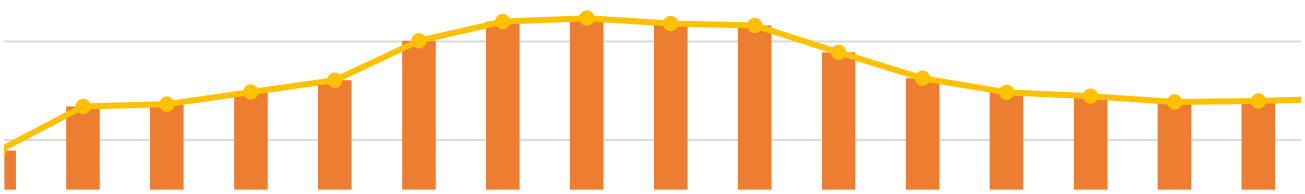
| 2018-Nov | 2019-May | 2019-Nov | 2020-May | 2020-Nov | 2021-May | 2021-Jul | 2021-Nov | 2022-May |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2019 | 2020 | 2020 | 2021 | 2021 | 2021 | 2022 |
| Nov | May | Nov | May | Nov | May | Jul | Nov | May |
| 11 | 5 | 11 | 5 | 11 | 5 | 7 | 11 | 5 |
| 43405 | 43586 | 43770 | 43952 | 44136 | 44317 | 44378 | 44501 | 44682 |
| 43404 | 43585 | 43769 | 43951 | 44135 | 44316 | 44377 | 44500 | 44681 |
| -562 | -535 | -462 | -431 | -348 | -98 | -213 | -233 | -197 |
| -564 | -617 | -721 | -781 | -784 | -250 | -546 | -697 | -657 |
| -1126 | -1152 | -1183 | -1212 | -1132 | -348 | -759 | -930 | -854 |

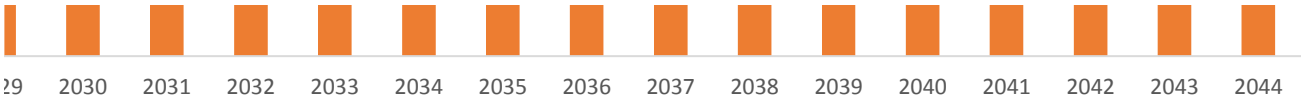
| 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 |
|---|---|---|---|---|---|---|---|---|
| (855) | (621) | (396) | (201) | (53) | 91 | 231 | 321 | 537 |
| (1523) | (1551) | (1289) | (859) | (436) | (49) | | | |
| (2378) | (2172) | (1684) | (1060) | (489) | 42 | 231 | 321 | 537 |
| (8274) | (10446) | (12130) | (13190) | (13679) | (13637) | (13406) | (13085) | (12549) |
| (1046) | (956) | (741) | (466) | (215) | 18 | 102 | 141 | 236 |

:.

| 2020-21 | 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 |
|---|---|---|---|---|---|---|---|---|
| (798) | (563) | (344) | (161) | (18) | 128 | 254 | 362 | 613 |
| (1555) | (1508) | (1191) | (752) | (329) | (12) | | | |
| (2353) | (2071) | (1535) | (913) | (347) | 116 | 254 | 362 | 613 |
| (8840) | (10911) | (12446) | (13359) | (13705) | (13590) | (13336) | (12973) | (12361) |
| (1035) | (911) | (675) | (402) | (152) | 51 | 112 | 159 | 270 |

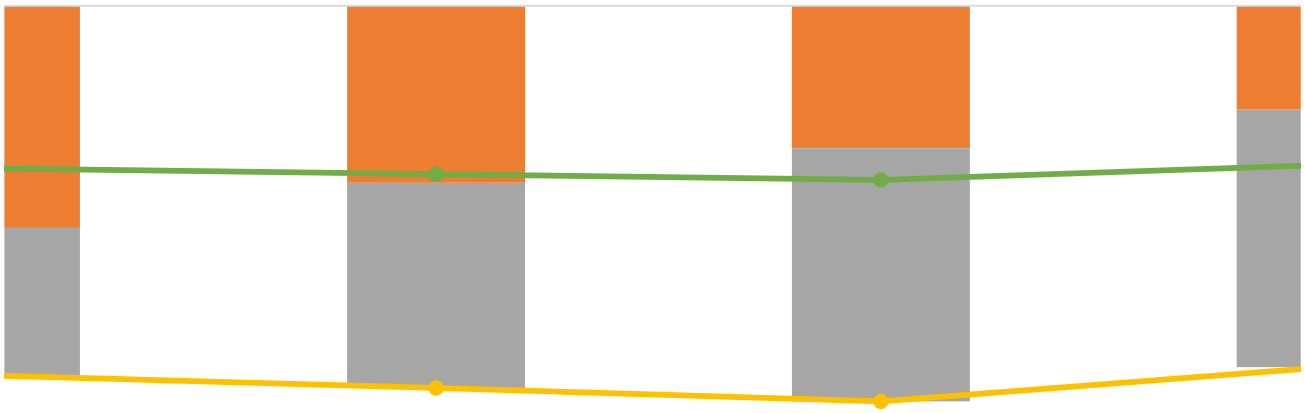
ro Plan GA Financing - Calendar Year






t amount Total Annual Borrowing Requirement OPG Equity Injection (44%)

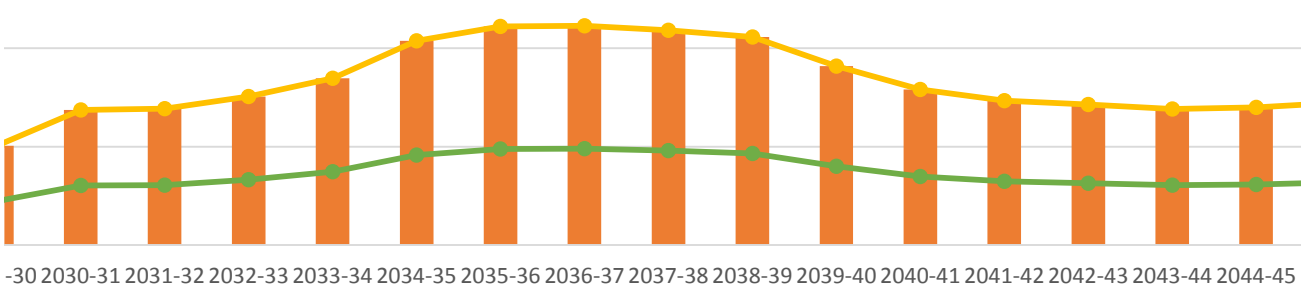
## ro Plan GA Financing - Calendar Year

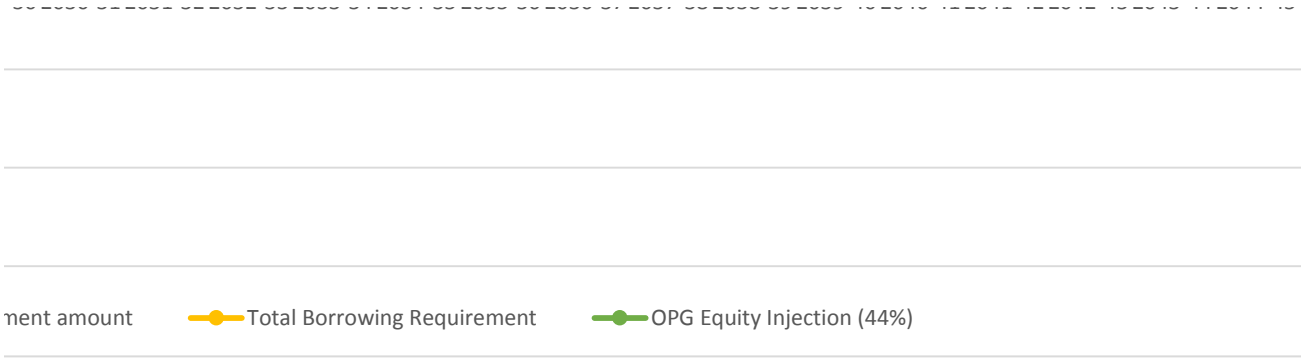


| 8 | 2019 | 2020 | |
|---|---|---|---|
| 5) | (1233) | (1523) | ( |
| 6) | (1064) | (855) | |
| 1) | (2297) | (2378) | ( |
| 7) | (1011) | (1046) | |

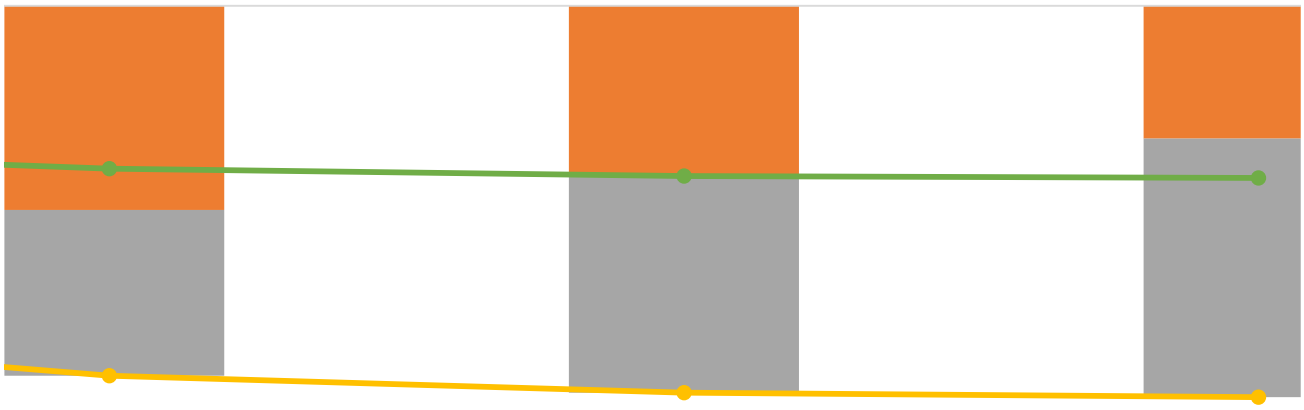
t amount Total Annual Borrowing Requirement OPG Equity Injection (44%)

## dro Plan GA Financing - Fiscal Year

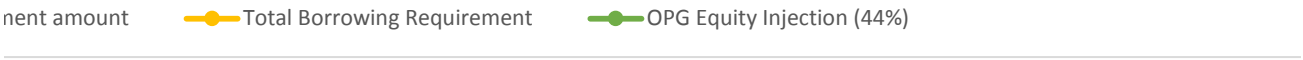





## dro Plan GA Financing - Fiscal Year



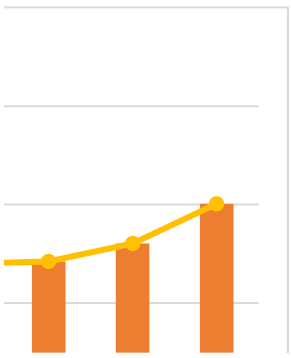
| 2018-19 | 2019-20 | 2020-21 |
|---|---|---|
| (997) | (1312) | (1555) |
| (1227) | (1014) | (798) |
| (2224) | (2326) | (2353) |
| (979) | (1023) | (1035) |

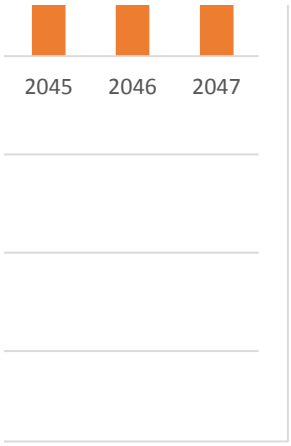


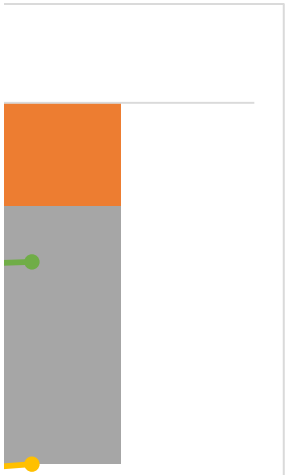
| 2022-Nov | 2023-May | 2023-Nov | 2024-May | 2024-Nov | 2025-May | 2025-Nov | 2026-May | 2026-Nov |
|---|---|---|---|---|---|---|---|---|
| 2022 | 2023 | 2023 | 2024 | 2024 | 2025.00 | 2025 | 2026 | 2026 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 44866 | 45047 | 45231 | 45413 | 45597 | 45778 | 45962 | 46143 | 46327 |
| 44865 | 45046 | 45230 | 45412 | 45596 | 45777 | 45961 | 46142 | 46326 |
| -130 | -98 | -50 | -27 | 21 | 45 | 95 | 121 | 141 |
| -501 | -429 | -287 | -220 | -73 | | | | |
| -631 | -527 | -337 | -247 | -52 | 45 | 95 | 121 | 141 |

| 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|---|---|
| 892 | 1340 | 1365 | 1486 | 1609 | 2007 | 2201 | 2237 | 2185 |
| 892 | 1340 | 1365 | 1486 | 1609 | 2007 | 2201 | 2237 | 2185 |
| (11657) | (10317) | (8952) | (7466) | (5858) | (3851) | (1649) | 588 | 2773 |
| 392 | 590 | 600 | 654 | 708 | 883 | 969 | 984 | 961 |

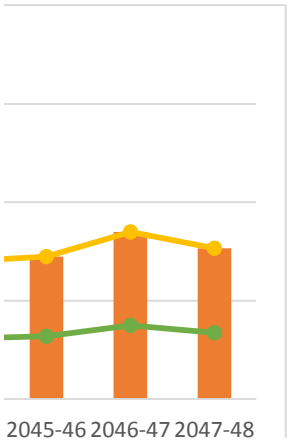
| 2029-30 | 2030-31 | 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 |
|---|---|---|---|---|---|---|---|---|
| 1010 | 1373 | 1385 | 1510 | 1694 | 2076 | 2221 | 2227 | 2183 |
| 1010 | 1373 | 1385 | 1510 | 1694 | 2076 | 2221 | 2227 | 2183 |
| (11351) | (9978) | (8593) | (7083) | (5389) | (3313) | (1092) | 1136 | 3318 |
| 444 | 604 | 609 | 664 | 745 | 913 | 977 | 980 | 960 |

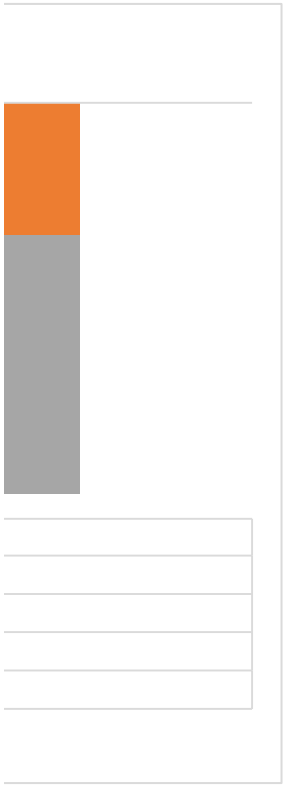




| 2021 |
|---|
| (1551) |
| (621) |
| (2172) |
| (956) |





| 2027-May | 2027-Nov | 2028-May | 2028-Nov | 2029-May | 2029-Nov | 2030-May | 2030-Nov | 2031-May |
|---|---|---|---|---|---|---|---|---|
| 2027 | 2027 | 2028 | 2028 | 2029 | 2029 | 2030 | 2030 | 2031 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 46508 | 46692 | 46874 | 47058 | 47239 | 47423 | 47604 | 47788 | 47969 |
| 46507 | 46691 | 46873 | 47057 | 47238 | 47422 | 47603 | 47787 | 47968 |
| 152 | 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 |
| 152 | 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|---|---|---|---|---|
| 2163 | 1892 | 1626 | 1484 | 1444 | 1385 | 1395 | 1421 | 1603 |
| 2163 | 1892 | 1626 | 1484 | 1444 | 1385 | 1395 | 1421 | 1603 |
| 4936 | 6828 | 8454 | 9938 | 11381 | 12767 | 14162 | 15583 | 17186 |
| 952 | 832 | 716 | 653 | 635 | 610 | 614 | 625 | 705 |

| 2038-39 | 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 | 2045-46 | 2046-47 |
|---|---|---|---|---|---|---|---|---|
| 2114 | 1820 | 1580 | 1468 | 1430 | 1383 | 1398 | 1449 | 1699 |
| 2114 | 1820 | 1580 | 1468 | 1430 | 1383 | 1398 | 1449 | 1699 |
| 5432 | 7252 | 8832 | 10300 | 11730 | 13113 | 14511 | 15960 | 17659 |
| 930 | 801 | 695 | 646 | 629 | 608 | 615 | 637 | 748 |

| 2031-Nov | 2032-May | 2032-Nov | 2033-May | 2033-Nov | 2034-May | 2034-Nov | 2035-May | 2035-Nov |
|---|---|---|---|---|---|---|---|---|
| 2031 | 2032 | 2032 | 2033 | 2033 | 2034 | 2034 | 2035 | 2035 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 48153 | 48335 | 48519 | 48700 | 48884 | 49065 | 49249 | 49430 | 49614 |
| 48152 | 48334 | 48518 | 48699 | 48883 | 49064 | 49248 | 49429 | 49613 |
| 719 | 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 |
| | | | | | | | | |
| 719 | 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 |

**2047**

2006

2006

19192

883

**2047-48**

1534

1534

19192

675

| **2036-May** | **2036-Nov** | **2037-May** | **2037-Nov** | **2038-May** | **2038-Nov** | **2039-May** | **2039-Nov** | **2040-May** |
|---|---|---|---|---|---|---|---|---|
| 2036 | 2036 | 2037 | 2037 | 2038 | 2038 | 2039 | 2039 | 2040 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 49796 | 49980 | 50161 | 50345 | 50526 | 50710 | 50891 | 51075 | 51257 |
| 49795 | 49979 | 50160 | 50344 | 50525 | 50709 | 50890 | 51074 | 51256 |
| 1129 | 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 |
| | | | | | | | | |
| 1129 | 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 |

| **2040-Nov** | **2041-May** | **2041-Nov** | **2042-May** | **2042-Nov** | **2043-May** | **2043-Nov** | **2044-May** | **2044-Nov** |
|---|---|---|---|---|---|---|---|---|
| 2040 | 2041 | 2041 | 2042 | 2042 | 2043 | 2043 | 2044 | 2044 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 51441 | 51622 | 51806 | 51987 | 52171 | 52352 | 52536 | 52718 | 52902 |
| 51440 | 51621 | 51805 | 51986 | 52170 | 52351 | 52535 | 52717 | 52901 |
| 756 | 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 |
| | | | | | | | | |
| 756 | 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 |

| **2045-May** | **2045-Nov** | **2046-May** | **2046-Nov** | **2047-May** | |
|---|---|---|---|---|---|
| 2045 | 2045 | 2046 | 2046 | 2047 | 2047.00 |
| May | Nov | May | Nov | May | Nov |
| 5 | 11 | 5 | 11 | 5 | 11 |
| 53083 | 53267 | 53448 | 53632 | 53813 | 53997 |
| 53082 | 53266 | 53447 | 53631 | 53812 | 53996 |
| 705 | 753 | 786 | 945 | 1376 | |
| | | | | | |
| 705 | 753 | 786 | 945 | 1376 | |

| | |
|---|---|
| Equity Injection | 44% |
| Assumed Interest Cost | 4.5% |

**Biennial**

| **$ nominal million** | **2017-Jul** | **2017-Nov** | **2018-May** |
|---|---|---|---|
| | 2017 | 2017 | 2018 |
| | Jul | Nov | May |
| | 7 | 11 | 5 |
| **First Date** | 42917 | 43040 | 43221 |
| | | 43039 | 43220 |
| Fair Allocation Amount | -931 | -779 | -629 |
| Readjustment amount | -74 | -341 | -470 |
| | | | |
| Total borrowing requirement including financing costs | -1005 | -1120 | -1099 |

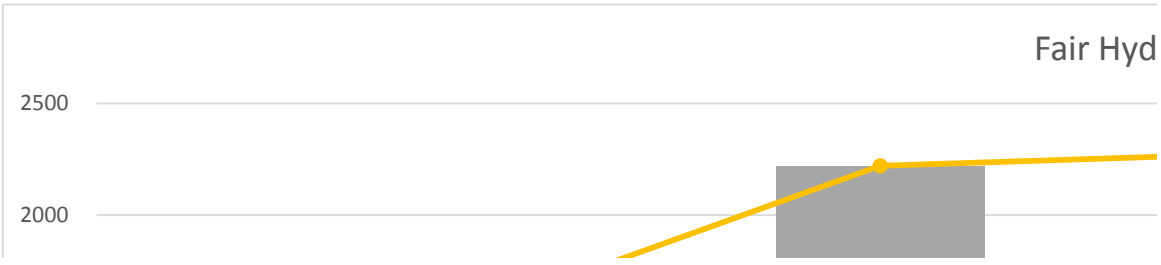
**Annual**

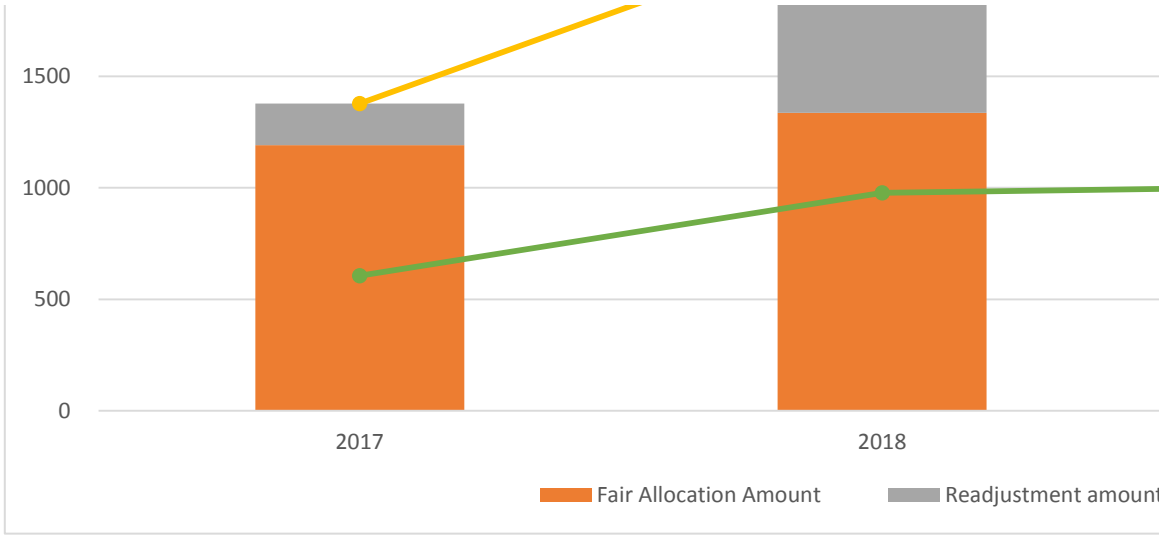
| **$ nominal million** | **2017** | **2018** | **2019** |
|---|---|---|---|
| Fair Allocation Amount | 1191 | 1336 | 1064 |
| Readjustment amount | 188 | 885 | 1233 |
| | | | |
| Total borrowing requirement including financing costs | 1378 | 2221 | 2297 |
| Accumulated borrowing requirement including financing costs | | 3599 | 5896 |
| OPG Equity Injection (44%)* | 606 | 977 | 1011 |

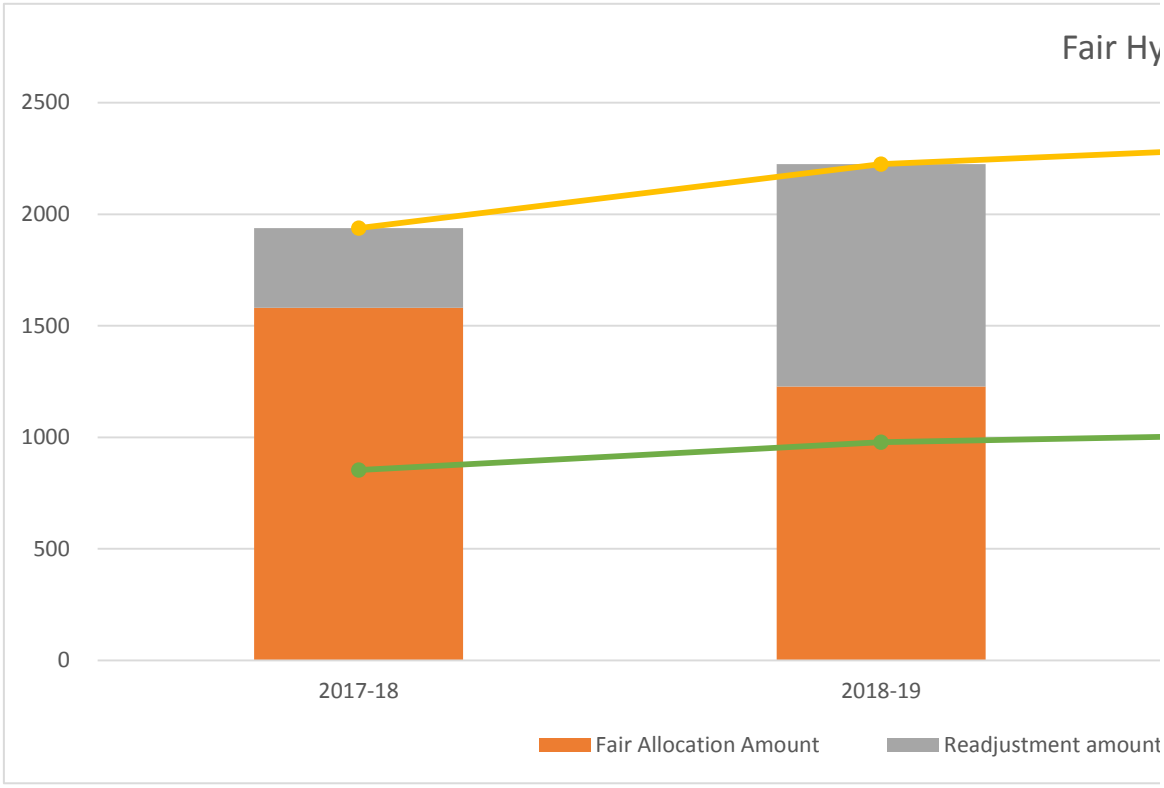
*This includes financing costs, which may need to be excluded upon further information available

**Fiscalized**

| **$ nominal million** | **2017-18** | **2018-19** | **2019-20** |
|---|---|---|---|
| Fair Allocation Amount | 1580 | 1227 | 1014 |
| Readjustment amount | 358 | 997 | 1312 |
| | | | |
| Total borrowing requirement including financing costs | 1938 | 2224 | 2326 |
| Accumulated borrowing requirement including financing costs | | 4162 | 6488 |
| OPG Equity Injection (44%)* | 853 | 979 | 1023 |




1500
1000
500
0
2017
2018
Fair Allocation Amount
Readjustment amount

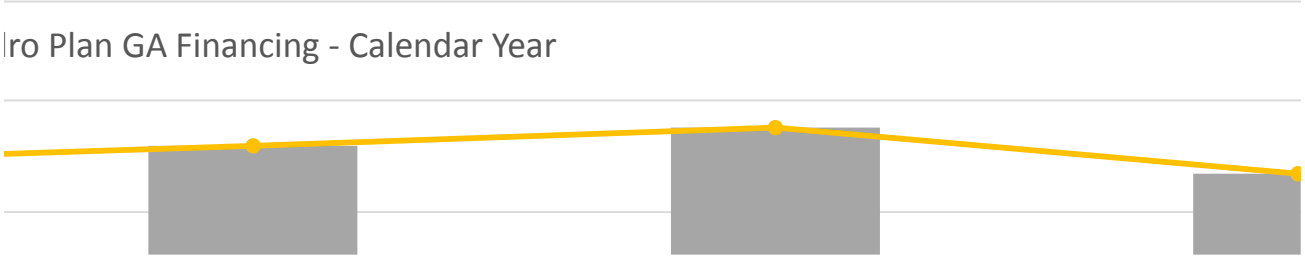

Fair Hy
2500
2000
1500
1000
500
0
2017-18
2018-19
Fair Allocation Amount
Readjustment amount

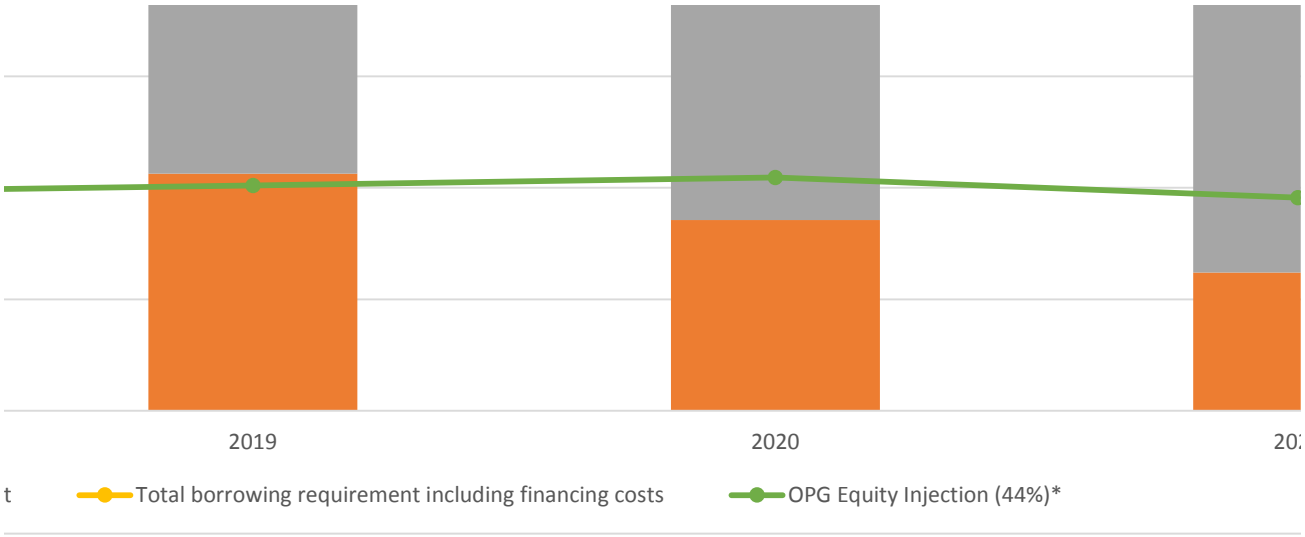
| 2018-Nov | 2019-May | 2019-Nov | 2020-May | 2020-Nov | 2021-May | 2021-Jul | 2021-Nov | 2022-May |
|---|---|---|---|---|---|---|---|---|
| 2018 | 2019 | 2019 | 2020 | 2020 | 2021 | 2021 | 2021 | 2022 |
| Nov | May | Nov | May | Nov | May | Jul | Nov | May |
| 11 | 5 | 11 | 5 | 11 | 5 | 7 | 11 | 5 |
| 43405 | 43586 | 43770 | 43952 | 44136 | 44317 | 44378 | 44501 | 44682 |
| 43404 | 43585 | 43769 | 43951 | 44135 | 44316 | 44377 | 44500 | 44681 |
| -562 | -535 | -462 | -431 | -348 | -98 | -213 | -233 | -197 |
| -564 | -617 | -721 | -781 | -784 | -250 | -546 | -697 | -657 |
| | | | | | | | | |
| -1126 | -1152 | -1183 | -1212 | -1132 | -348 | -759 | -930 | -854 |

| 2020 | 2021 |
|---|---|
| 855 | 621 |
| 1523 | 1551 |
| | |
| 2378 | 2172 |
| | |
| 8274 | 10446 |
| 1046 | 956 |

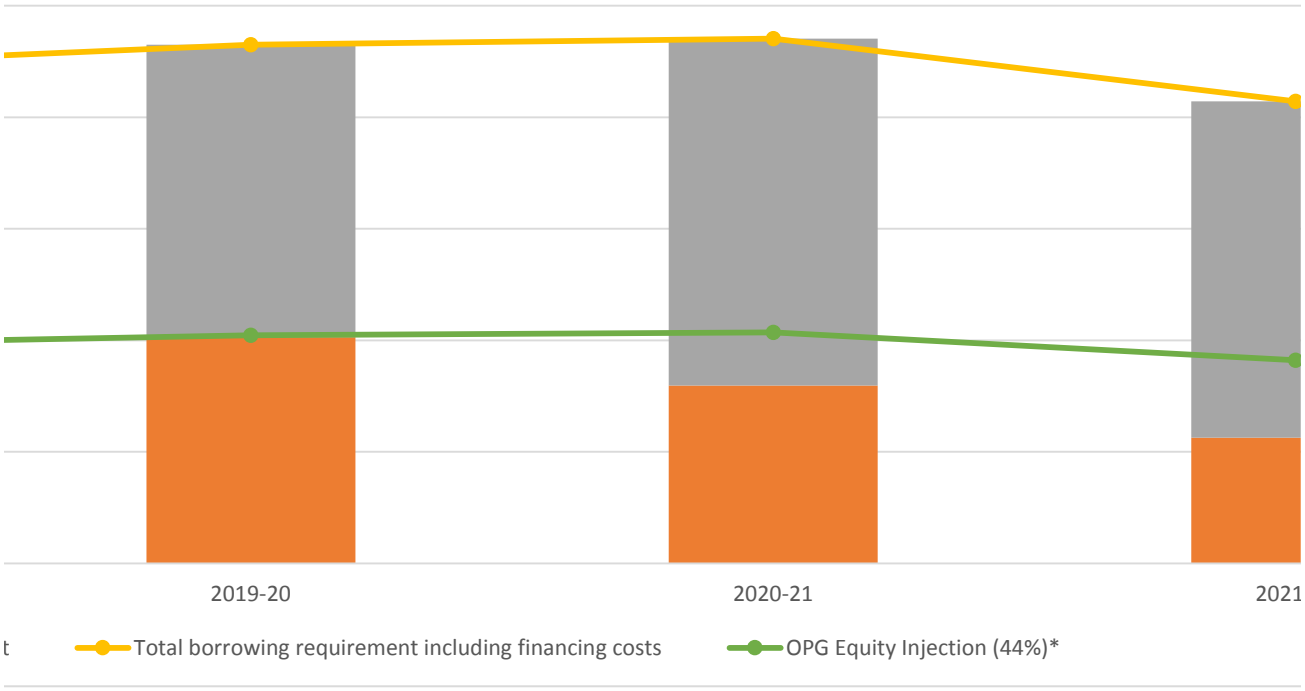
:.

| 2020-21 | 2021-22 |
|---|---|
| 798 | 563 |
| 1555 | 1508 |
| | |
| 2353 | 2071 |
| | |
| 8840 | 10911 |
| 1035 | 911 |

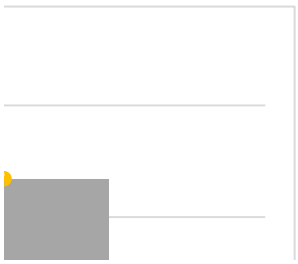


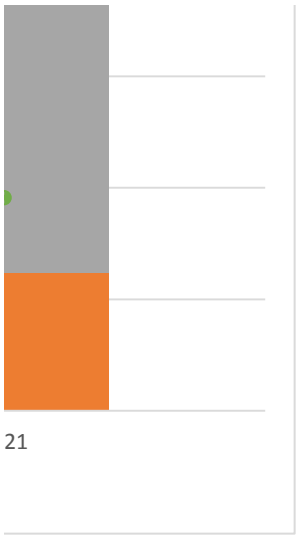


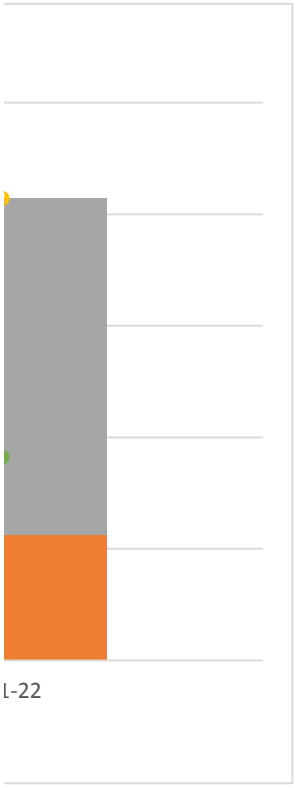

## ydro Plan GA Financing - Fiscal Year



| **2022-Nov** | **2023-May** | **2023-Nov** | **2024-May** | **2024-Nov** | **2025-May** | **2025-Nov** | **2026-May** | **2026-Nov** |
|---|---|---|---|---|---|---|---|---|
| 2022 | 2023 | 2023 | 2024 | 2024 | 2025.00 | 2025 | 2026 | 2026 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 44866 | 45047 | 45231 | 45413 | 45597 | 45778 | 45962 | 46143 | 46327 |
| 44865 | 45046 | 45230 | 45412 | 45596 | 45777 | 45961 | 46142 | 46326 |
| -130 | -98 | -50 | -27 | 21 | 45 | 95 | 121 | 141 |
| -501 | -429 | -287 | -220 | -73 | | | | |
| | | | | | | | | |
| -631 | -527 | -337 | -247 | -52 | 45 | 95 | 121 | 141 |




21


l-22

| **2027-May** | **2027-Nov** | **2028-May** | **2028-Nov** | **2029-May** | **2029-Nov** | **2030-May** | **2030-Nov** | **2031-May** |
|---|---|---|---|---|---|---|---|---|
| 2027 | 2027 | 2028 | 2028 | 2029 | 2029 | 2030 | 2030 | 2031 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 46508 | 46692 | 46874 | 47058 | 47239 | 47423 | 47604 | 47788 | 47969 |
| 46507 | 46691 | 46873 | 47057 | 47238 | 47422 | 47603 | 47787 | 47968 |
| 152 | 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 |
| | | | | | | | | |
| 152 | 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 |

| **2031-Nov** | **2032-May** | **2032-Nov** | **2033-May** | **2033-Nov** | **2034-May** | **2034-Nov** | **2035-May** | **2035-Nov** |
|---|---|---|---|---|---|---|---|---|
| 2031 | 2032 | 2032 | 2033 | 2033 | 2034 | 2034 | 2035 | 2035 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 48153 | 48335 | 48519 | 48700 | 48884 | 49065 | 49249 | 49430 | 49614 |
| 48152 | 48334 | 48518 | 48699 | 48883 | 49064 | 49248 | 49429 | 49613 |
| 719 | 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 |
| | | | | | | | | |
| 719 | 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 |

| **2036-May** | **2036-Nov** | **2037-May** | **2037-Nov** | **2038-May** | **2038-Nov** | **2039-May** | **2039-Nov** | **2040-May** |
|---|---|---|---|---|---|---|---|---|
| 2036 | 2036 | 2037 | 2037 | 2038 | 2038 | 2039 | 2039 | 2040 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 49796 | 49980 | 50161 | 50345 | 50526 | 50710 | 50891 | 51075 | 51257 |
| 49795 | 49979 | 50160 | 50344 | 50525 | 50709 | 50890 | 51074 | 51256 |
| 1129 | 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 |
| | | | | | | | | |
| 1129 | 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 |

| **2040-Nov** | **2041-May** | **2041-Nov** | **2042-May** | **2042-Nov** | **2043-May** | **2043-Nov** | **2044-May** | **2044-Nov** |
|---|---|---|---|---|---|---|---|---|
| 2040 | 2041 | 2041 | 2042 | 2042 | 2043 | 2043 | 2044 | 2044 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 51441 | 51622 | 51806 | 51987 | 52171 | 52352 | 52536 | 52718 | 52902 |
| 51440 | 51621 | 51805 | 51986 | 52170 | 52351 | 52535 | 52717 | 52901 |
| 756 | 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 |
| | | | | | | | | |
| 756 | 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 |

| **2045-May** | **2045-Nov** | **2046-May** | **2046-Nov** | **2047-May** | |
|---|---|---|---|---|---|
| 2045 | 2045 | 2046 | 2046 | 2047 | 2047.00 |
| May | Nov | May | Nov | May | Nov |
| 5 | 11 | 5 | 11 | 5 | 11 |
| 53083 | 53267 | 53448 | 53632 | 53813 | 53997 |
| 53082 | 53266 | 53447 | 53631 | 53812 | 53996 |
| 705 | 753 | 786 | 945 | 1376 | |
| | | | | | |
| 705 | 753 | 786 | 945 | 1376 | |

Equity Injection 44%

**Biennial**

| **$ nominal million** | **2017-Jul** | **2017-Nov** | **2018-May** | **2018-Nov** |
|---|---|---|---|---|
| | 2017 Jul | 2017 Nov | 2018 May | 2018 Nov |
| | 7 | 11 | 5 | 11 |
| **First Date** | 42917 | 43040 | 43221 | 43405 |
| | | 43039 | 43220 | 43404 |
| Fair Allocation Amount | -931 | -779 | -629 | -562 |
| Readjustment amount | -74 | -341 | -470 | -564 |
| Total borrowing requirement including financing costs | -1005 | -1120 | -1099 | -1126 |
| | $1,539.67 | | | |

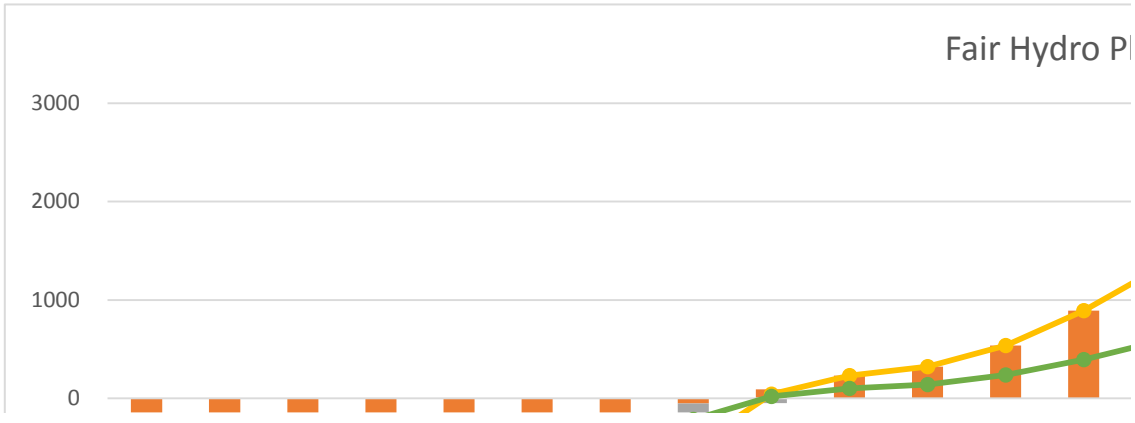
**Annual**

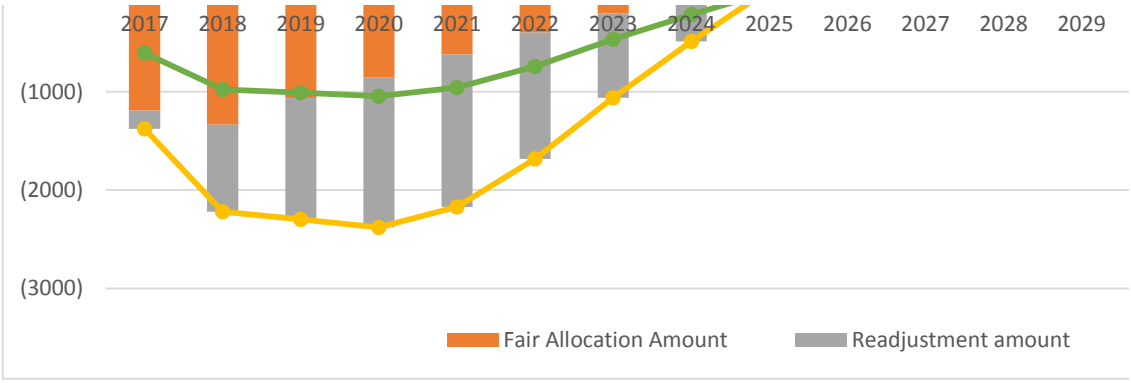
| **$ nominal million** | **2017** | **2018** | **2019** | **2020** |
|---|---|---|---|---|
| Fair Allocation Amount | (1191) | (1336) | (1064) | (855) |
| Readjustment amount | (188) | (885) | (1233) | (1523) |
| Total borrowing requirement including financing costs | (1378) | (2221) | (2297) | (2378) |
| OPG Equity Injection (44%)* | (606) | (977) | (1011) | (1046) |

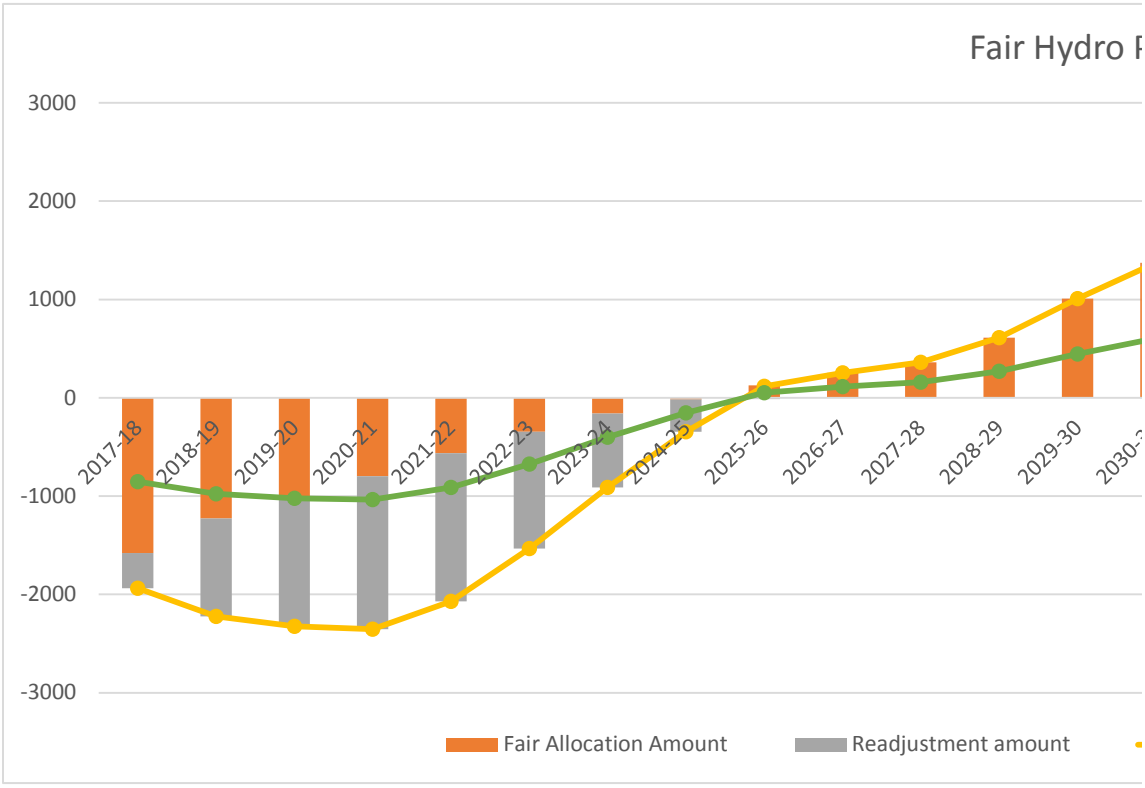
*This includes financing costs, which may need to be excluded upon further information availal

**Fiscalized**

| **$ nominal million** | **2017-18** | **2018-19** | **2019-20** | **2020-21** |
|---|---|---|---|---|
| Fair Allocation Amount | -1580.167 | -1227.167 | -1013.6667 | -798 |
| Readjustment amount | -358.1667 | -996.8333 | -1311.8333 | -1554.5 |
| Total borrowing requirement including financing costs | -1938.333 | -2224 | -2325.5 | -2352.5 |
| OPG Equity Injection (44%)* | -852.8667 | -978.56 | -1023.22 | -1035.1 |




2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
(1000)
(2000)
(3000)
Fair Allocation Amount
Readjustment amount


Fair Hydro F
3000
2000
1000
0
-1000
-2000
-3000
2017-18
2018-19
2019-20
2020-21
2021-22
2022-23
2023-24
2024-25
2025-26
2026-27
2027-28
2028-29
2029-30
Fair Allocation Amount
Readjustment amount

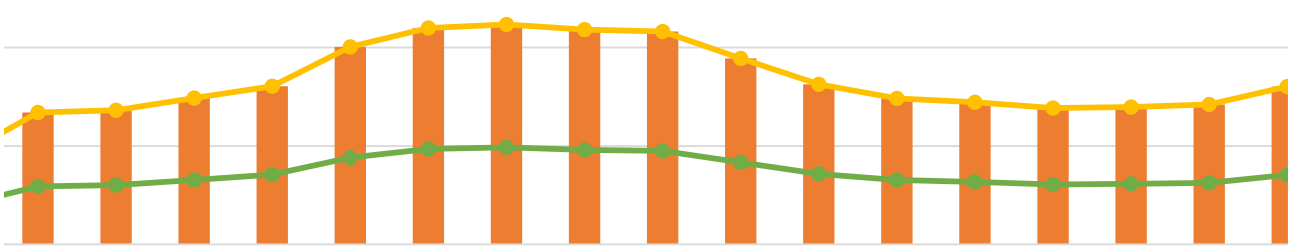
| 2019-May | 2019-Nov | 2020-May | 2020-Nov | 2021-May | 2021-Jul | 2021-Nov | 2022-May | 2022-Nov |
|---|---|---|---|---|---|---|---|---|
| 2019 | 2019 | 2020 | 2020 | 2021 | 2021 | 2021 | 2022 | 2022 |
| May | Nov | May | Nov | May | Jul | Nov | May | Nov |
| 5 | 11 | 5 | 11 | 5 | 7 | 11 | 5 | 11 |
| 43586 | 43770 | 43952 | 44136 | 44317 | 44378 | 44501 | 44682 | 44866 |
| 43585 | 43769 | 43951 | 44135 | 44316 | 44377 | 44500 | 44681 | 44865 |
| -535 | -462 | -431 | -348 | -98 | -213 | -233 | -197 | -130 |
| -617 | -721 | -781 | -784 | -250 | -546 | -697 | -657 | -501 |
| | | | | | | | | |
| -1152 | -1183 | -1212 | -1132 | -348 | -759 | -930 | -854 | -631 |

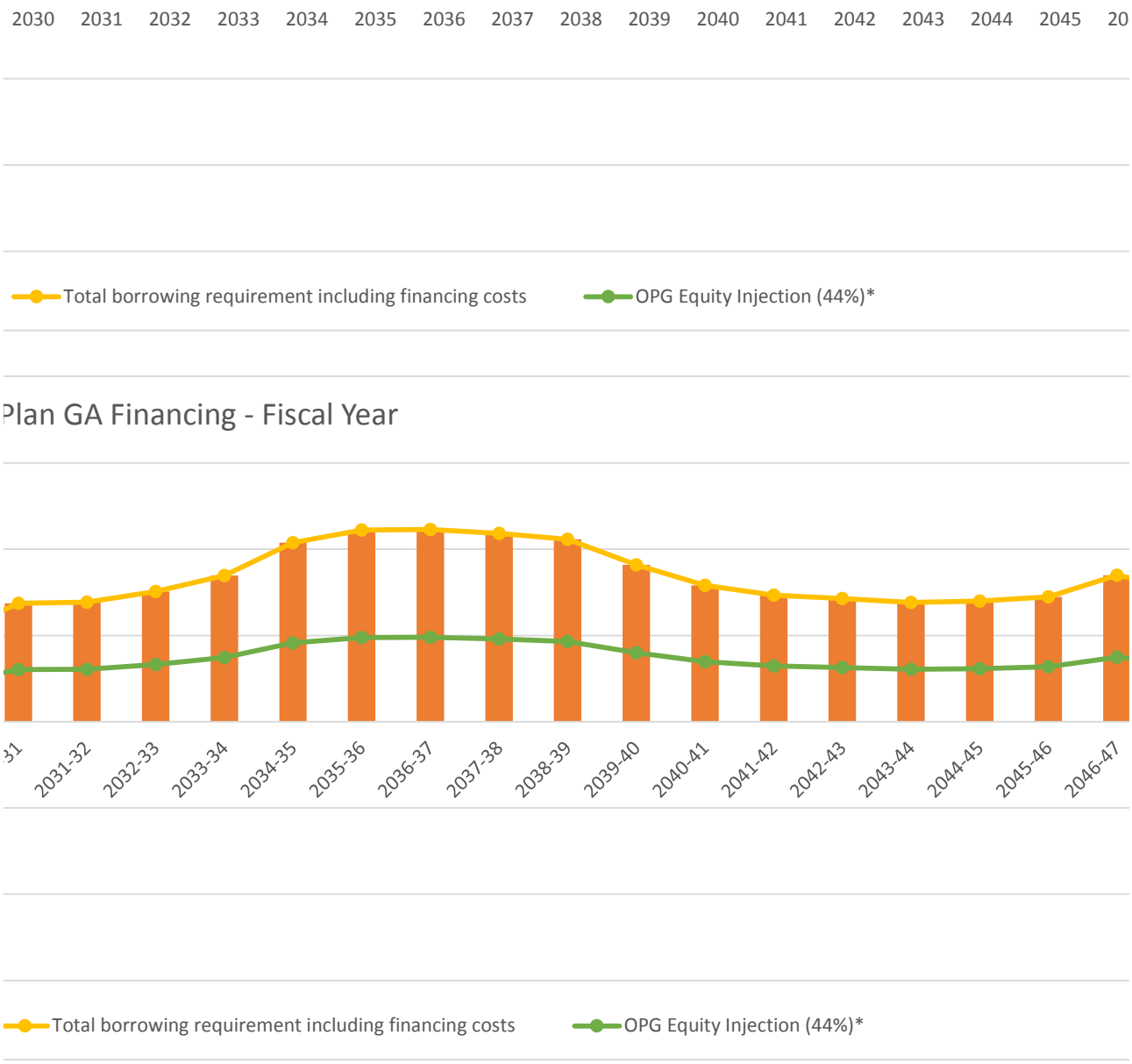
| 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 |
|---|---|---|---|---|---|---|---|---|
| (621) | (396) | (201) | (53) | 91 | 231 | 321 | 537 | 892 |
| (1551) | (1289) | (859) | (436) | (49) | 0 | 0 | 0 | 0 |
| | | | | | | | | |
| (2172) | (1684) | (1060) | (489) | 42 | 231 | 321 | 537 | 892 |
| | | | | | | | | |
| (956) | (741) | (466) | (215) | 18 | 102 | 141 | 236 | 392 |

ble.

| 2021-22 | 2022-23 | 2023-24 | 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 |
|---|---|---|---|---|---|---|---|---|
| -563.1667 | -344.1667 | -161.3333 | -17.83333 | 127.66667 | 254.333 | 362.1667 | 612.66667 | 1009.667 |
| -1507.5 | -1190.667 | -751.6667 | -328.6667 | -12.16667 | 0 | 0 | 0 | 0 |
| | | | | | | | | |
| -2070.667 | -1534.833 | -913 | -346.5 | 115.5 | 254.333 | 362.1667 | 612.66667 | 1009.667 |
| | | | | | | | | |
| -911.0933 | -675.3267 | -401.72 | -152.46 | 50.82 | 111.907 | 159.3533 | 269.57333 | 444.2533 |

## Ian GA Financing - Calendar Year

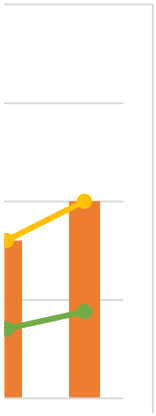



2030 2031 2032 2033 2034 2035 2036 2037 2038 2039 2040 2041 2042 2043 2044 2045 20
Total borrowing requirement including financing costs
OPG Equity Injection (44%)*
Plan GA Financing - Fiscal Year
31 2031-32 2032-33 2033-34 2034-35 2035-36 2036-37 2037-38 2038-39 2039-40 2040-41 2041-42 2042-43 2043-44 2044-45 2045-46 2046-47
Total borrowing requirement including financing costs
OPG Equity Injection (44%)*

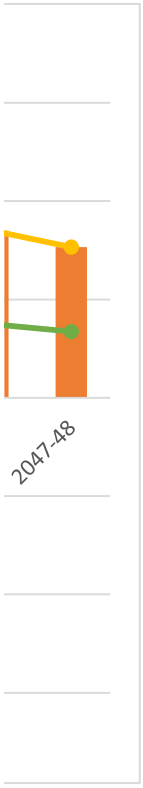
| 2023-May | 2023-Nov | 2024-May | 2024-Nov | 2025-May | 2025-Nov | 2026-May | 2026-Nov | 2027-May |
|---|---|---|---|---|---|---|---|---|
| 2023 | 2023 | 2024 | 2024 | 2025.00 | 2025 | 2026 | 2026 | 2027 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 45047 | 45231 | 45413 | 45597 | 45778 | 45962 | 46143 | 46327 | 46508 |
| 45046 | 45230 | 45412 | 45596 | 45777 | 45961 | 46142 | 46326 | 46507 |
| -98 | -50 | -27 | 21 | 45 | 95 | 121 | 141 | 152 |
| -429 | -287 | -220 | -73 | | | | | |
| -527 | -337 | -247 | -52 | 45 | 95 | 121 | 141 | 152 |

| 2030 | 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|---|---|---|---|---|
| 1340 | 1365 | 1486 | 1609 | 2007 | 2201 | 2237 | 2185 | 2163 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1340 | 1365 | 1486 | 1609 | 2007 | 2201 | 2237 | 2185 | 2163 |
| 590 | 600 | 654 | 708 | 883 | 969 | 984 | 961 | 952 |

| 2030-31 | 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 | 2038-39 |
|---|---|---|---|---|---|---|---|---|
| 1373 | 1385.167 | 1510 | 1693.667 | 2076 | 2221.333 | 2227.3333 | 2182.667 | 2113.5 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1373 | 1385.167 | 1510 | 1693.667 | 2076 | 2221.333 | 2227.3333 | 2182.667 | 2113.5 |
| 604.12 | 609.4733 | 664.4 | 745.2133 | 913.44 | 977.3867 | 980.02667 | 960.3733 | 929.94 |




46
2047


2047-48

| 2027-Nov | 2028-May | 2028-Nov | 2029-May | 2029-Nov | 2030-May | 2030-Nov | 2031-May | 2031-Nov |
|---|---|---|---|---|---|---|---|---|
| 2027 | 2028 | 2028 | 2029 | 2029 | 2030 | 2030 | 2031 | 2031 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 46692 | 46874 | 47058 | 47239 | 47423 | 47604 | 47788 | 47969 | 48153 |
| 46691 | 46873 | 47057 | 47238 | 47422 | 47603 | 47787 | 47968 | 48152 |
| 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 | 719 |
| 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 | 719 |

| 2039 | 2040 | 2041 | 2042 | 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|---|---|---|---|
| 1892 | 1626 | 1484 | 1444 | 1385 | 1395 | 1421 | 1603 | 2006 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1892 | 1626 | 1484 | 1444 | 1385 | 1395 | 1421 | 1603 | 2006 |
| 832 | 716 | 653 | 635 | 610 | 614 | 625 | 705 | 883 |

| 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 | 2045-46 | 2046-47 | 2047-48 |
|---|---|---|---|---|---|---|---|---|
| 1820 | 1580.3333 | 1468.167 | 1429.6667 | 1382.833 | 1398 | 1448.833 | 1699 | 1533.5 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1820 | 1580.3333 | 1468.167 | 1429.6667 | 1382.833 | 1398 | 1448.833 | 1699 | 1533.5 |
| 800.8 | 695.34667 | 645.9933 | 629.05333 | 608.4467 | 615.12 | 637.4867 | 747.56 | 674.74 |

| 2032-May | 2032-Nov | 2033-May | 2033-Nov | 2034-May | 2034-Nov | 2035-May | 2035-Nov | 2036-May |
|---|---|---|---|---|---|---|---|---|
| 2032 | 2032 | 2033 | 2033 | 2034 | 2034 | 2035 | 2035 | 2036 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 48335 | 48519 | 48700 | 48884 | 49065 | 49249 | 49430 | 49614 | 49796 |
| 48334 | 48518 | 48699 | 48883 | 49064 | 49248 | 49429 | 49613 | 49795 |
| 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 | 1129 |
| | | | | | | | | |
| 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 | 1129 |

| **2036-Nov** | **2037-May** | **2037-Nov** | **2038-May** | **2038-Nov** | **2039-May** | **2039-Nov** | **2040-May** | **2040-Nov** |
|---|---|---|---|---|---|---|---|---|
| 2036 | 2037 | 2037 | 2038 | 2038 | 2039 | 2039 | 2040 | 2040 |
| Nov | May | Nov | May | Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 |
| 49980 | 50161 | 50345 | 50526 | 50710 | 50891 | 51075 | 51257 | 51441 |
| 49979 | 50160 | 50344 | 50525 | 50709 | 50890 | 51074 | 51256 | 51440 |
| 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 | 756 |
| | | | | | | | | |
| 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 | 756 |

| 2041-May | 2041-Nov | 2042-May | 2042-Nov | 2043-May | 2043-Nov | 2044-May | 2044-Nov | 2045-May |
|---|---|---|---|---|---|---|---|---|
| 2041 | 2041 | 2042 | 2042 | 2043 | 2043 | 2044 | 2044 | 2045 |
| May | Nov | May | Nov | May | Nov | May | Nov | May |
| 5 | 11 | 5 | 11 | 5 | 11 | 5 | 11 | 5 |
| 51622 | 51806 | 51987 | 52171 | 52352 | 52536 | 52718 | 52902 | 53083 |
| 51621 | 51805 | 51986 | 52170 | 52351 | 52535 | 52717 | 52901 | 53082 |
| 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 | 705 |
| | | | | | | | | |
| 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 | 705 |

| **2045-Nov** | **2046-May** | **2046-Nov** | **2047-May** | |
|---|---|---|---|---|
| 2045 | 2046 | 2046 | 2047 | 2047.00 |
| Nov | May | Nov | May | Nov |
| 11 | 5 | 11 | 5 | 11 |
| 53267 | 53448 | 53632 | 53813 | 53997 |
| 53266 | 53447 | 53631 | 53812 | 53996 |
| 753 | 786 | 945 | 1376 | |
| | | | | |
| 753 | 786 | 945 | 1376 | |

| **$ nominal million** | **2017-Jul** | **2017-Nov** | **2018-May** | **2018-Nov** |
|---|---|---|---|---|
| Fair Allocation Amount | -931 | -779 | -629 | -562 |
| Readjustment amount | -74 | -341 | -470 | -564 |
| Total borrowing requirement including financing costs | -1005 | -1120 | -1099 | -1126 |

| 2019-May | 2019-Nov | 2020-May | 2020-Nov | 2021-May | 2021-Jul | 2021-Nov | 2022-May | 2022-Nov |
|---|---|---|---|---|---|---|---|---|
| -535 | -462 | -431 | -348 | -98 | -213 | -233 | -197 | -130 |
| -617 | -721 | -781 | -784 | -250 | -546 | -697 | -657 | -501 |
| | | | | | | | | |
| -1152 | -1183 | -1212 | -1132 | -348 | -759 | -930 | -854 | -631 |

| 2023-May | 2023-Nov | 2024-May | 2024-Nov | 2025-May | 2025-Nov | 2026-May | 2026-Nov | 2027-May |
|---|---|---|---|---|---|---|---|---|
| -98 | -50 | -27 | 21 | 45 | 95 | 121 | 141 | 152 |
| -429 | -287 | -220 | -73 | | | | | |
| | | | | | | | | |
| -527 | -337 | -247 | -52 | 45 | 95 | 121 | 141 | 152 |

| 2027-Nov | 2028-May | 2028-Nov | 2029-May | 2029-Nov | 2030-May | 2030-Nov | 2031-May | 2031-Nov |
|---|---|---|---|---|---|---|---|---|
| 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 | 719 |
| 224 | 262 | 376 | 437 | 612 | 706 | 678 | 673 | 719 |

| 2032-May | 2032-Nov | 2033-May | 2033-Nov | 2034-May | 2034-Nov | 2035-May | 2035-Nov | 2036-May |
|---|---|---|---|---|---|---|---|---|
| 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 | 1129 |
| 751 | 767 | 785 | 937 | 1024 | 1075 | 1113 | 1115 | 1129 |

| 2036-Nov | 2037-May | 2037-Nov | 2038-May | 2038-Nov | 2039-May | 2039-Nov | 2040-May | 2040-Nov |
|---|---|---|---|---|---|---|---|---|
| 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 | 756 |
| 1095 | 1091 | 1091 | 1105 | 992 | 948 | 848 | 809 | 756 |

| 2041-May | 2041-Nov | 2042-May | 2042-Nov | 2043-May | 2043-Nov | 2044-May | 2044-Nov | 2045-May |
|---|---|---|---|---|---|---|---|---|
| 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 | 705 |
| 738 | 725 | 728 | 697 | 690 | 692 | 701 | 698 | 705 |

| 2045-Nov | 2046-May | 2046-Nov | 2047-May |
|---|---|---|---|
| 753 | 786 | 945 | 1376 |
| 753 | 786 | 945 | 1376 |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 3.66% | *<-- Change this number to test differ* |
| Basis Points | 00 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 3.6602% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 3.66% | |
| **Year Interest Payments Stop:** | ~~2047~~ | *<-- To Be Update* |
| **Total Interest Paid:** | 11,088 | *NOTE: Calculations do not match En* |
| **Peak Debt:** | 18,485 | |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 11,088 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |

**WEIGHTED AVERAGE:**

| | |
|---|---|
| FHT Weighted Average Rate: | 3.660% |
| FHT Interest Paid | 11,088 |
| Peak Debt: | 18,485 |
| | |
| Provincial Borrowing at Issuance: | 3.20% *Source: OFA* |
| Provincial Interest Paid: | 8,887 |
| Peak Debt: | 17,752 |
| | |
| **Difference in Interest Paid:** | **2,201** |
| **Difference in Peak Debt:** | **733** |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɨs*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.520% | *Source: Debt Issuance* |
| 3.74% | *Source: National Bank of Canada - Indicative Pricing (20yr)* |
| 4.04% | *Source: National Bank of Canada - Indicative Pricing (20yr)* |

| |
|---|
| **3.660%** |

**INPUTS:**

| Calculation for Scenario Analysis | |
|---|---|
| Provincial Borrowing | 4.50% |
| Basis Points | 00 bp |
| Total (Interest Rate) | 4.50% |

**OUTPUTS:**

| Interest Calculation | |
|---|---|
| **Interest Rate:** | 4.50% |
| **Year Interest Payments Stop:** | 2047 |
| **Total Interest Paid:** | 14,308 |
| **Peak Debt:** | 17,612 |
| **Annual Paydown Amount:** | (1,278) |

**SCENARIOS:**

| | 3.12% | |
|---|---|---|
| **Interest Rate:** | 3.12% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 9,038 | |
| **Peak Debt:** | 16,348 | |
| **Annual Paydown Amount:** | (1,038) | |
| **Difference in Interest Paid:** | | 1,4 |

## Scenario Analysis with EFB Model

| 3.12% + 40bp | 4.50% | 4.5% + 50bp |
|---|---|---|
| 3.52% | 4.50% | 5.00% |
| 2047 | 2047 | 2047 |
| 10,477 | 14,308 | 16,438 |
| 16,705 | 17,612 | 18,093 |
| (1,104) | (1,278) | (1,375) |
| 39 | 2,130 | |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 26 |
| Closing Debt Balance [EFB Calculation] | 1,422 |

***-6.11***

## Attempted recreation and extrapolation by EFB ($ nominal Million)

**Interest:**
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| **2017** |
|---|

| | |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** | |
| ***(Exactly from above)*** | 1,396 |
| *Reduction* | |
| **Opening Debt:** | 0 |
| **IN YEAR ANALYSIS** | |
| **In-Year Interest:** | 29 |
| **In-Year Accumulated Debt (Excl Interest):** | 1,396 |
| **In-Year - End Debt:** | 1,425 |
| **Debt Interest from Prior Year:** | 0 |
| **Total Accumulated Interest:** | 29 |
| **Accumulated Debt:** | 1,396 |
| **Debt Reduction:** | |
| **Closing Debt:** | 1,425 |

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| | 116 | 225 | 343 | 466 | 577 |
| | 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

3.66%
**2047**
**11,088**
**18,485**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|
| | 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | | Additional Borrowing/F |
| | 94 | 181 | 275 | 372 | 458 |
| | 3,705 | 6,182 | 8,871 | 11,447 | 13,605 |
| | ***-28.42*** | ***-72.19*** | ***-140.17*** | ***-233.90*** | ***-352.28*** |

4.50%
**2047**
**14,308**
**17,612**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 1,425 | 3,724 | 6,235 | 8,980 | 11,634 |
| 46 | 48 | 50 | 46 | 36 |
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 2,235 | 2,344 | 2,464 | 2,250 | 1,736 |
| 64 | 168 | 281 | 404 | 524 |
| 110 | 216 | 331 | 450 | 559 |
| 3,614 | 6,020 | 8,649 | 11,184 | 13,334 |
| 3,724 | 6,235 | 8,980 | 11,634 | 13,894 |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | | | | |
| | Cross Over Point: | (61) | | |
| | Borrrowing Still Required: | | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 527 | 575 | 606 | 628 | 652 |
| 15,182 | 16,249 | 16,855 | 17,484 | 18,136 |
| | | | | |
| ***-492.16*** | ***-649.83*** | ***-821.94*** | ***-1007.29*** | ***-1206.66*** |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1,050 | 492 | 61 | | |
| | | | -1278 | -1278 |
| 13,894 | 15,591 | 16,794 | 17,612 | 17,127 |
| | | | | |
| 22 | 10 | 1 | 0 | 0 |
| 1,050 | 492 | 61 | 0 | 0 |
| 1,072 | 502 | 62 | 0 | 0 |
| | | | | |
| 625 | 702 | 756 | 793 | 771 |
| | | | | |
| 647 | 712 | 757 | 793 | 771 |
| 14,944 | 16,083 | 16,855 | 17,612 | 17,127 |
| | | | (1,278) | (1,278) |
| | | | | |
| 15,591 | 16,794 | 17,612 | 17,127 | 16,620 |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| | | | | |
| 33.45 | (182) | | | |
| 670 | 673 | 658 | 637 | 613 |
| 18,485 | 18,262 | 17,669 | 17,117 | 16,383 |
| | | | | |
| ***-1419.51*** | ***-1642.71*** | ***-1872.67*** | ***-2108.30*** | ***-2349.26*** |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|

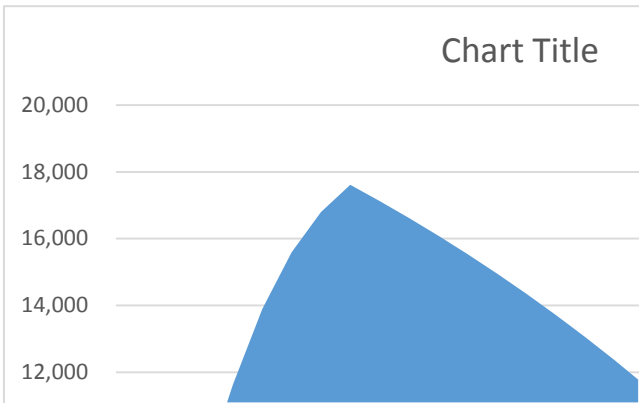
| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 748 | 724 | 699 | 673 | 646 |
| 748 | 724 | 699 | 673 | 646 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 16,090 | 15,537 | 14,958 | 14,354 | 13,722 |

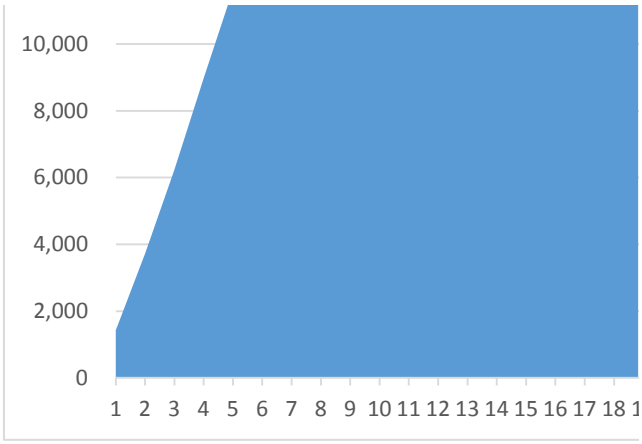
| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 584 | 544 | 490 | 430 | 368 |
| 15,548 | 14,192 | 12,595 | 10,897 | 9,202 |
| ***-2594.57*** | ***-2841.76*** | ***-3087.64*** | ***-3330.69*** | ***-3570.36*** |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 617 | 588 | 557 | 524 | 490 |
| 617 | 588 | 557 | 524 | 490 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 13,062 | 12,372 | 11,651 | 10,897 | 10,110 |




10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 1

| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

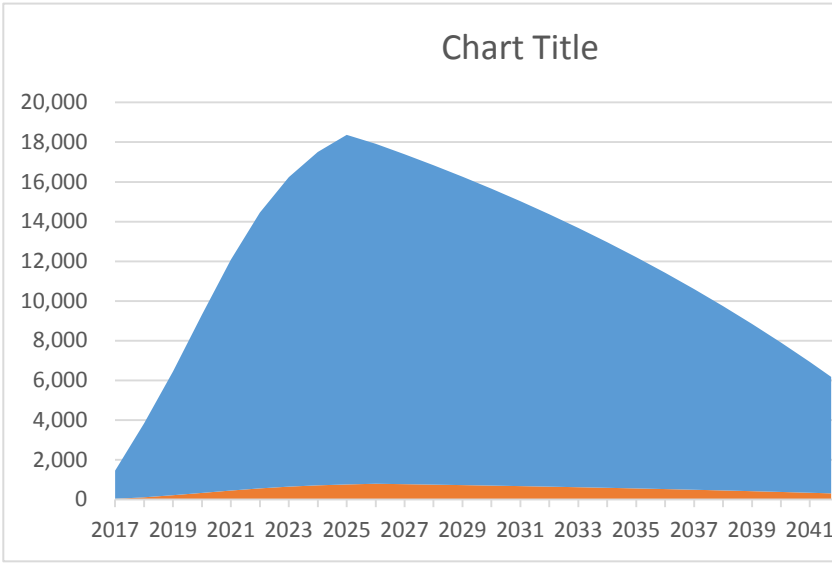


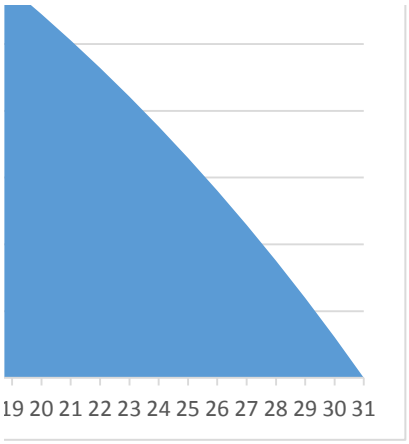
| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|
| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
| | | | | |
| 304 | 243 | 190 | 142 | 96 |
| 7,408 | 5,854 | 4,517 | 3,267 | 1,985 |
| ***-3806.07*** | ***-4038.25*** | ***-4268.71*** | ***-4498.66*** | ***-4728.32*** |



| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 455 | 418 | 379 | 339 | 297 |
| 455 | 418 | 379 | 339 | 297 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 9,287 | 8,427 | 7,529 | 6,590 | 5,609 |




19 20 21 22 23 24 25 26 27 28 29 30 31

| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |

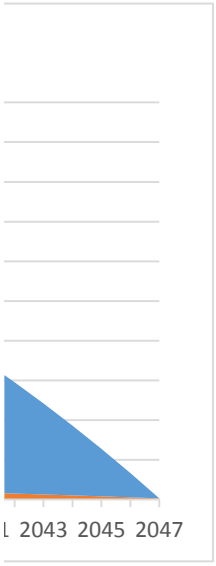


| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| | | | | |
| 50 | 2 | (48) | (104) | (174) |
| 724 | (615) | (2,020) | (3,650) | (5,857) |
| ***-4957.63*** | ***-5186.32*** | ***-5413.76*** | ***-5638.63*** | ***-5857.37*** |



| **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) | (2,613) |



| 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) | (17,685) |

| 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 |
|---|---|---|---|---|---|---|

| | |
|---|---|
| -1278 | -1278 |
| | |
| (17,685) | (19,758) |
| | |
| | |
| 0 | 0 |
| 0 | 0 |
| 0 | 0 |
| | |
| (796) | (889) |
| | |
| (796) | (889) |
| (17,685) | (19,758) |
| (1,278) | (1,278) |
| | |
| (19,758) | (21,925) |

**Instructions: An updated projection of the annual cost of the refinancing portion of the Fa**

**Please contact Matt Gurham (mgurham@fao-on.org) if assistance is required.**

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayment Amount Cash Flows**

| *$ millions* |
|---|
| IESO forecast Global Adjustment cost * |
| Global Adjustment payment from ratepayer ** |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for all customers (2017-203
** Represents total OFHP costs recovered from consumers, including deferral of GA and recovery of

**Provincial Actual and Projected Fair Hydro Plan Debt**

| *$ millions* |
|---|
| Amount borrowed/paid-back in given year*** |
| Interest**** ~~on accumulated debt from previous year~~ |
| Accumulated Debt |

***Values represent deferral of GA costs and recovery of principal.
****Interest is calculated based on the average debt balance for the year and a 5 per cent interest ra
This data was used to inform the Minister's letter to OPG.

**OPG Actual and Projected Fair Hydro Plan Debt**

| *$ million* |
|---|
| Amount borrowed/paid-back in given year |
| Interest on accumulated debt from previous year |
| Accumulated Debt |

## Equity Injection Comparisons

Revised Annual Borrowings
Equity Injection (44%)

Revised Equity Injections - Fiscalized
EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)
Variance

## IOD Comparisons

***Revised Equity Injections - Fiscalized***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

***EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

**Variance in IOD Impacts**

**ıir Hydro Plan.**

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 10,078 | 10,144 | 10,801 | 10,576 | 9,671 | 9,471 | 8,733 |
| 8,682 | 7,955 | 8,505 | 8,162 | 7,467 | 7,771 | 7,683 |

:5) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by assuming 2% CPI
principal, interest and fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| -1,448 | -2,322 | -2,553 | -2,808 | -2,740 | -2,363 | -1,819 |
| 52 | 133 | 257 | 394 | 536 | 663 | 769 |
| 1,448 | 3,770 | 6,323 | 9,131 | 11,871 | 14,234 | 16,053 |

ate over the 30-year life of the program, and includes associated fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 1,448 | 2,322 | 2,553 | 2,808 | 2,740 | 2,363 | 1,819 |
| 637 | 1022 | 1123 | 1235 | 1206 | 1040 | 800 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 |
|---|---|---|---|---|---|---|
| 893 | 1047 | 1151 | 1228 | 1164 | 980 | 748 |
| 853 | 979 | 1023 | 1035 | 911 | 675 | 402 |
| 40 | 69 | 128 | 193 | 253 | 305 | 346 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|
| 893 | 1,047 | 1,151 | 1,228 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 11 | 21 | 21 | 21 |
| | 18 | 35 | 35 |
| | | 23 | 46 |
| | | | 27 |
| **11** | **39** | **80** | **130** |
| | | | |
| 853 | 979 | 1,023 | 1,035 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 10 | 20 | 20 | 20 |
| | 16 | 33 | 33 |
| | | 21 | 41 |
| | | | 23 |
| **10** | **37** | **74** | **117** |
| | | | |
| **0** | **2** | **6** | **13** |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 9,917 | 8,924 | 9,908 | 10,169 | 10,300 | 9,978 | 9,472 |
| 9,425 | 8,924 | 9,908 | 10,169 | 11,297 | 11,009 | 10,877 |

and extrapolated post-2035 based on the average rate of change between 2026-2035.

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| -1,342 | -907 | -954 | -1,004 | -33 | 0 | 385 |
| 850 | 907 | 954 | 1,004 | 1,030 | 1,031 | 1,021 |
| 17,395 | 18,301 | 19,255 | 20,259 | 20,292 | 20,292 | 19,907 |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 1,342 | 907 | 954 | 1,004 | 33 | 0 | -385 |
| 590 | 399 | 420 | 442 | 15 | 0 | -169 |

| 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 |
|---|---|---|---|---|---|---|
| 542 | 404 | 425 | 335 | 11 | -42 | -164 |
| 152 | -51 | -112 | -159 | -270 | -444 | -604 |
| 390 | 455 | 537 | 494 | 281 | 402 | 440 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 | 4,771 | 4,417 | 4,089 |
| 9,789 | 9,840 | 9,009 | 8,291 | 6,988 | 6,666 | 6,262 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 337 | 515 | 611 | 1,131 | 1,372 | 1,477 | 1,476 |
| 1,003 | 981 | 952 | 908 | 845 | 772 | 697 |
| 19,570 | 19,055 | 18,444 | 17,313 | 15,941 | 14,464 | 12,988 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| -337 | -515 | -611 | -1,131 | -1,372 | -1,477 | -1,476 |
| -148 | -227 | -269 | -498 | -604 | -650 | -650 |

| 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 |
|---|---|---|---|---|---|---|
| -168 | -237 | -326 | -524 | -615 | -650 | -661 |
| -609 | -664 | -745 | -913 | -977 | -980 | -960 |
| 442 | 427 | 419 | 389 | 362 | 330 | 299 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 3,785 | 3,504 | 3,244 | 3,003 | 2,780 | 2,574 | 2,383 |
| 5,985 | 5,392 | 4,855 | 4,474 | 4,230 | 3,948 | 3,780 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 1,580 | 1,343 | 1,128 | 1,041 | 1,075 | 1,053 | 1,132 |
| 620 | 545 | 483 | 429 | 375 | 321 | 265 |
| 11,408 | 10,065 | 8,937 | 7,895 | 6,821 | 5,768 | 4,636 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| -1,580 | -1,343 | -1,128 | -1,041 | -1,075 | -1,053 | -1,132 |
| -695 | -591 | -496 | -458 | -473 | -463 | -498 |

| 2038-39 | 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 |
|---|---|---|---|---|---|---|
| -669 | -567 | -487 | -462 | -470 | -472 | -505 |
| -930 | -801 | -695 | -646 | -629 | -608 | -615 |
| 261 | 234 | 208 | 184 | 159 | 137 | 110 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 2,206 | 2,042 | 1,891 | 1,750 |
| 3,611 | 3,608 | 3,952 | 1,750 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 1,199 | 1,427 | 2,010 | 0 |
| 206 | 139 | 51 | 0 |
| 3,437 | 2,010 | 0 | 0 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| -1,199 | -1,427 | -2,010 | 0 |
| -528 | -628 | -885 | 0 |

| 2045-46 | 2046-47 | 2047-48 |
|---|---|---|
| -553 | -692 | -663 |
| -637 | -748 | -675 |
| 85 | 56 | 11 |

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayme**

| *$ millions* | **2017** | **2018** |
|---|---|---|
| IESO forecast Global A | 10,078 | 10,144 |
| Global Adjustment pay | 8,682 | 7,955 |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for a
** Represents total OFHP costs recovered from consumers, including deferral

| | | |
|---|---|---|
| Deferral | 1,396 | 2,189 |
| | 52 | 133 |
| Annual Borrowings | 1,448 | 2,322 |
| TOTAL | 1,448 | 3,770 |
| | | |
| | 0.03719145 | 0.060789592 |
| | 0.035857845 | 0.035294613 |
| | 0.03719145 | 0.036585899 |
| | 0.0358578446 | 0.0510000000 |
| | 0.0371914498 | 0.0537407798 |
| | 0.0371914498 | 0.0523345305 |
| | | |
| | 5% | |
| | | |
| Recalculation | 1,396 | 2,189 |
| | 52 | 130 |
| | 1,448 | 2,319 |
| | 1,448 | 3,768 |

**nt Amount Cash Flows**

| 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|
| 10,801 | 10,576 | 9,671 | 9,471 |
| 8,505 | 8,162 | 7,467 | 7,771 |

ll customers (2017-2035) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by
of GA and recovery of principal, interest and fees.

| | | | |
|---|---|---|---|
| 2,296 | 2,414 | 2,204 | 1,700 |
| 257 | 394 | 536 | 663 |
| 2,553 | 2,808 | 2,740 | 2,363 |
| 6,323 | 9,131 | 11,871 | 14,234 |
| | | | |
| 0.112122144 | 0.163279846 | 0.242946991 | 0.390032973 |
| 0.040704571 | 0.043159126 | 0.045114332 | 0.046583166 |
| 0.042431736 | 0.045105856 | 0.047245794 | 0.048859181 |
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0508000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0535187526 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0521239483 |
| | 0.050837963 | | |
| | | | |
| 2,296 | 2,414 | 2,204 | 1,700 |
| 252 | 386 | 524 | 651 |
| 2,548 | 2,799 | 2,728 | 2,351 |
| 6,315 | 9,115 | 11,843 | 14,194 |

| 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|
| 8,733 | 9,917 | 8,924 | 9,908 |
| 7,683 | 9,425 | 8,924 | 9,908 |

y assuming 2% CPI and extrapolated post-2035 based on the average rate of change between 2026-2035.

| | | | |
|---|---|---|---|
| 1,050 | 492 | 0 | 0 |
| 769 | 850 | 907 | 954 |
| 1,819 | 1,342 | 907 | 954 |
| 16,053 | 17,395 | 18,301 | 19,255 |
| | | | |
| 0.73265484 | 1.72677531 | #DIV/0! | #DIV/0! |
| 0.047921434 | 0.048841011 | 0.049541642 | 0.049541642 |
| 0.050333487 | 0.051348946 | 0.052123948 | 0.052123948 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 1,050 | 492 | 0 | 0 |
| 755 | 833 | 888 | 934 |
| 1,805 | 1,325 | 888 | 934 |
| 15,999 | 17,324 | 18,212 | 19,146 |

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| 10,169 | 10,300 | 9,978 | 9,472 |
| 10,169 | 11,297 | 11,009 | 10,877 |

| | | | |
|---|---|---|---|
| 0 | -997 | -1,031 | -1,406 |
| 1,004 | 1,030 | 1,031 | 1,021 |
| 1,004 | 33 | 0 | -385 |
| 20,259 | 20,292 | 20,292 | 19,907 |
| | | | |
| #DIV/0! | -1.033303874 | -1 | -0.726329513 |
| | | | |
| 0.052123948 | 0.053472634 | 0.053518753 | 0.054063854 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 0 | -997 | -1,031 | -1,406 |
| 982 | 1007 | 1006 | 995 |
| 982 | 10 | -25 | -410 |
| 20,128 | 20,138 | 20,113 | 19,703 |

| 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 |
| 9,789 | 9,840 | 9,009 | 8,291 |

| | | | |
|---|---|---|---|
| -1,340 | -1,496 | -1,564 | -2,039 |
| 1,003 | 981 | 952 | 908 |
| -337 | -515 | -611 | -1,131 |
| 19,570 | 19,055 | 18,444 | 17,313 |
| | | | |
| -0.748423197 | -0.655724615 | -0.609140601 | |
| | | | |
| 0.054004521 | 0.054281378 | 0.054453742 | 0.055363212 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| -1,340 | -1,496 | -1,564 | -2,039 |
| 976 | 953 | 924 | 879 |
| -364 | -543 | -640 | -1,160 |
| 19,339 | 18,796 | 18,156 | 16,996 |

| 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|
| 4,771 | 4,417 | 4,089 | 3,785 |
| 6,988 | 6,666 | 6,262 | 5,985 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 845 | 772 | 697 | 620 |
| -1,372 | -1,477 | -1,476 | -1,580 |
| 15,941 | 14,464 | 12,988 | 11,408 |

| | | | |
|---|---|---|---|
| 0.055951526 | | | |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 815 | 742 | 667 | 589 |
| -1,402 | -1,507 | -1,507 | -1,611 |
| 15,594 | 14,087 | 12,580 | 10,968 |

| 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|
| 3,504 | 3,244 | 3,003 | 2,780 |
| 5,392 | 4,855 | 4,474 | 4,230 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 545 | 483 | 429 | 375 |
| -1,343 | -1,128 | -1,041 | -1,075 |
| 10,065 | 8,937 | 7,895 | 6,821 |

| | | | |
|---|---|---|---|
| 0.0508000000 | 0.0508000000 | 0.0510000000 | 0.0510000000 |
| 0.0535187526 | 0.0535187526 | 0.0537407798 | 0.0537407798 |
| 0.0521239483 | 0.0521239483 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 514 | 451 | 395 | 340 |
| -1,374 | -1,160 | -1,076 | -1,110 |
| 9,595 | 8,434 | 7,358 | 6,249 |

| 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|
| 2,574 | 2,383 | 2,206 | 2,042 |
| 3,948 | 3,780 | 3,611 | 3,608 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 321 | 265 | 206 | 139 |
| -1,053 | -1,132 | -1,199 | -1,427 |
| 5,768 | 4,636 | 3,437 | 2,010 |

| | | | |
|---|---|---|---|
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0510000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0537407798 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 285 | 229 | 169 | 101 |
| -1,088 | -1,168 | -1,236 | -1,464 |
| 5,160 | 3,992 | 2,756 | 1,291 |

| 2047 | 2048 |
|---|---|
| 1,891 | 1,750 |
| 3,952 | 1,750 |

| | |
|---|---|
| -2,062 | 0 |
| 51 | 0 |
| -2,010 | 0 |
| 0 | 0 |

| | |
|---|---|
| 0.0510000000 | 0.0000000000 |
| 0.0537407798 | 0.0000000000 |
| 0.0523345305 | 0.0000000000 |

| | |
|---|---|
| -2,062 | 0 |
| 13 | -39 |
| -2,048 | -39 |
| -757 | -796 |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 3.71% | *<-- Change this number to test differ* |
| Basis Points | 00 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 3.7119% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 3.71% | |
| **Year Interest Payments Stop:** | 2045 | |
| **Total Interest Paid:** | 11,368 | *NOTE: Calculations do not match En* |
| **Peak Debt:** | 18,569 | |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 11,368 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |

**WEIGHTED AVERAGE:**

| | |
|---|---|
| FHT Weighted Average Rate: | 3.712% |
| FHT Interest Paid | 11,088 |
| Peak Debt: | 18,485 |
| | |
| Provincial Borrowing at Issuance: | 3.20% *Source: OFA* |
| Provincial Interest Paid: | 8,887 |
| Peak Debt: | 17,752 |
| | |
| **Difference in Interest Paid:** | **2,201** |
| **Difference in Peak Debt:** | **733** |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɪs*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.520% | *Source: Debt Issuance Document* |
| 3.834% | *Source: Debt Issuance Document* |
| 4.214% | *Source: Debt Issuance Document* |

| |
|---|
| **3.712%** |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 26 |
| Closing Debt Balance [EFB Calculation] | 1,423 |

***-5.74***

| 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| 116 | 225 | 343 | 466 | 577 |
| 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

3.71%

**2045** *(note: array formula)*

**11,368**

**18,569**

| **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | Additional Borrowing/F |
| 95 | 184 | 280 | 378 | 466 |
| 3,707 | 6,186 | 8,879 | 11,461 | 13,627 |
| ***-26.68*** | ***-67.79*** | ***-131.64*** | ***-219.70*** | ***-330.96*** |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | Cross Over Point: | (61) | | |
| | Borrrowing Still Required: | | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 535 | 585 | 616 | 639 | 664 |
| 15,212 | 16,289 | 16,905 | 17,544 | 18,207 |
| ***-462.45*** | ***-610.73*** | ***-772.66*** | ***-947.11*** | ***-1134.84*** |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

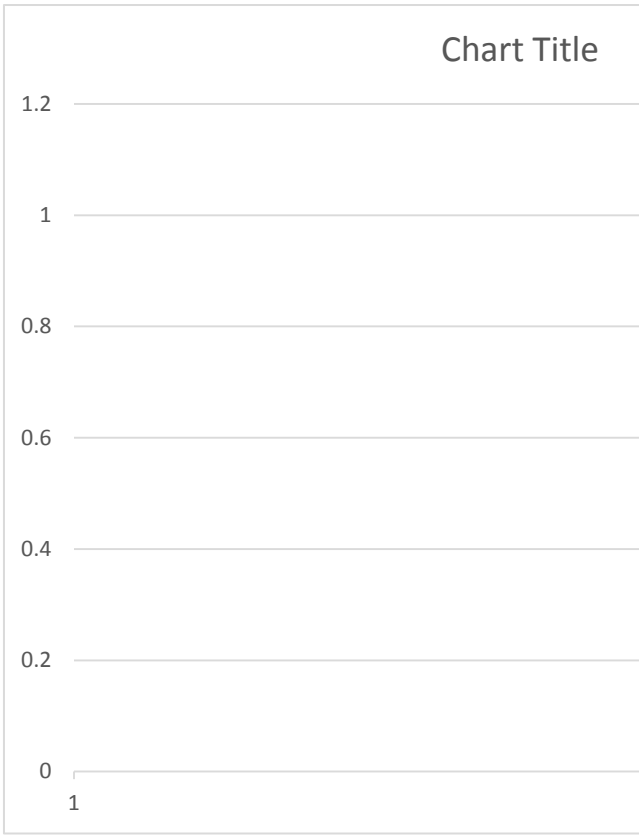


| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 683 | 685 | 671 | 650 | 627 |
| 18,569 | 18,359 | 17,779 | 17,241 | 16,520 |
| ***-1335.34*** | ***-1545.69*** | ***-1762.53*** | ***-1984.85*** | ***-2212.33*** |

| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

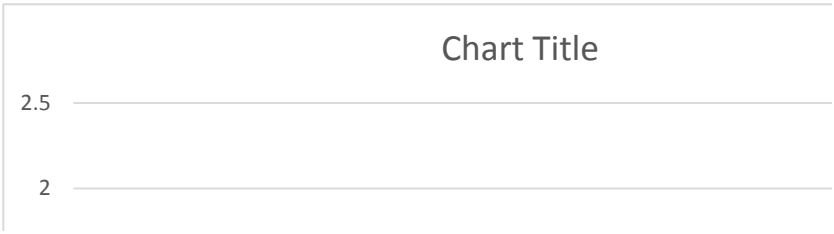


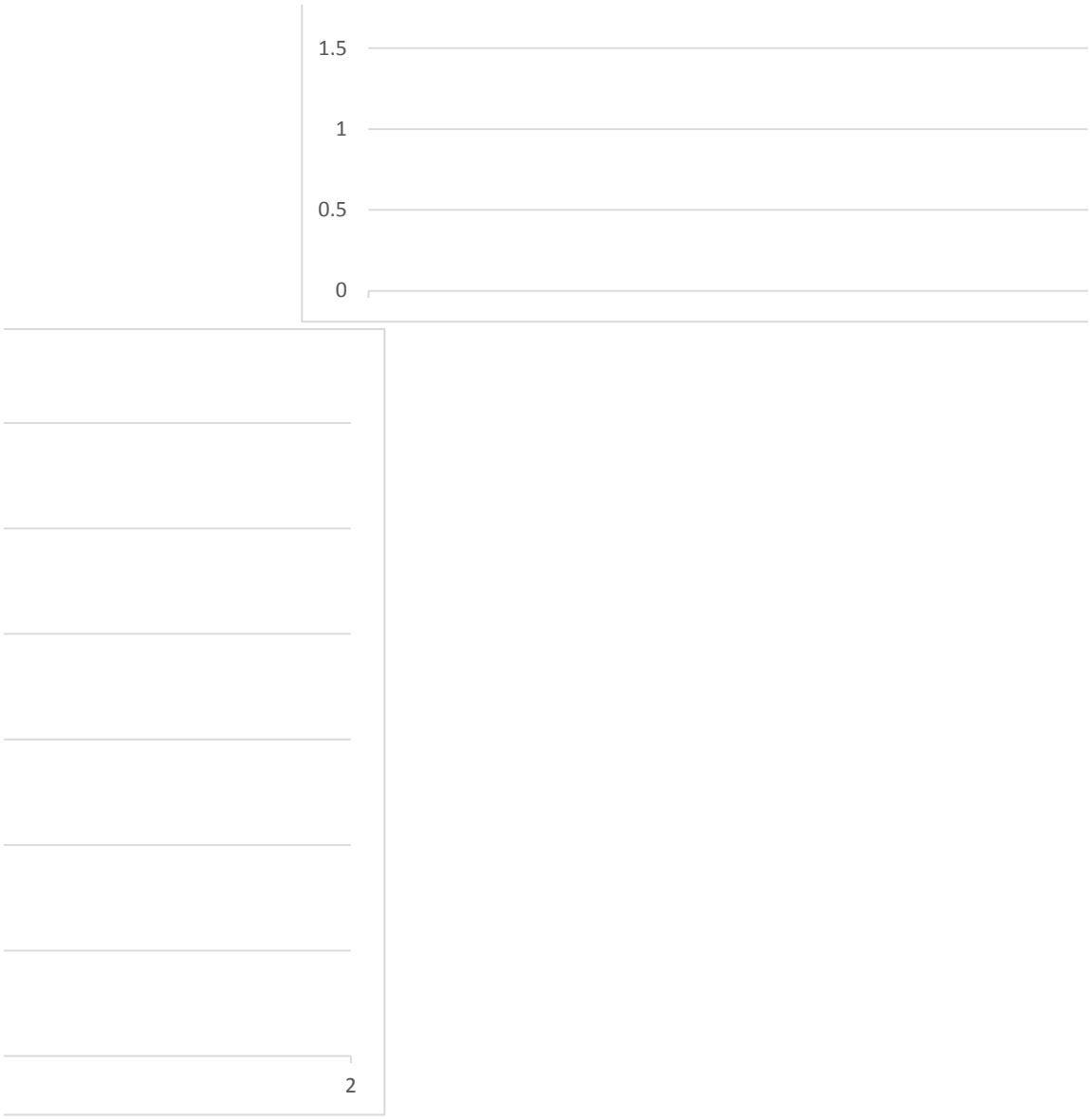
| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 598 | 558 | 503 | 443 | 380 |
| 15,698 | 14,356 | 12,772 | 11,087 | 9,405 |
| ***-2444.06*** | ***-2677.73*** | ***-2910.37*** | ***-3140.53*** | ***-3367.72*** |


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| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

| **2038** | **2039** | **2040** | **2041** | **2042** |
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| 7,622 | 6,081 | 4,755 | 3,516 | 2,244 |
| ***-3591.40*** | ***-3811.97*** | ***-4031.14*** | ***-4250.06*** | ***-4468.94*** |




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| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |



| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 60 | 12 | (38) | (94) | (165) |
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| ***-4687.72*** | ***-4906.18*** | ***-5123.72*** | ***-5339.11*** | ***-5549.02*** |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 3.71% | *<-- Change this number to test differ* |
| Basis Points | 00 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 3.7119% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 3.71% | |
| **Year Interest Payments Stop:** | 2045 | |
| **Total Interest Paid:** | 11,368 | *NOTE: Calculations do not match En* |
| **Peak Debt:** | 18,569 | |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 11,368 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |

**WEIGHTED AVERAGE:**

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.712% | |
| FHT Interest Paid | 11,368 | |
| Peak Debt: | 18,569 | |
| | | |
| Provincial Borrowing at Issuance: | 3.20% | *Source: OFA* |
| Provincial Interest Paid: | 8,887 | |
| Peak Debt: | 17,752 | |
| | | |
| **Difference in Interest Paid:** | **2,481** | |
| **Difference in Peak Debt:** | **817** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɪs*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.520% | *Source: Debt Issuance Document* |
| 3.834% | *Source: Debt Issuance Document* |
| 4.214% | *Source: Debt Issuance Document* |

| |
|---|
| **3.712%** |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 26 |
| Closing Debt Balance [EFB Calculation] | 1,423 |

***-5.74***

| 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| 116 | 225 | 343 | 466 | 577 |
| 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

3.71%

**2045** *(note: array formula)*

**11,368**

**18,569**

| **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | Additional Borrowing/F |
| 95 | 184 | 280 | 378 | 466 |
| 3,707 | 6,186 | 8,879 | 11,461 | 13,627 |
| ***-26.68*** | ***-67.79*** | ***-131.64*** | ***-219.70*** | ***-330.96*** |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | Cross Over Point: | (61) | | |
| | Borrrowing Still Required: | | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 535 | 585 | 616 | 639 | 664 |
| 15,212 | 16,289 | 16,905 | 17,544 | 18,207 |
| ***-462.45*** | ***-610.73*** | ***-772.66*** | ***-947.11*** | ***-1134.84*** |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

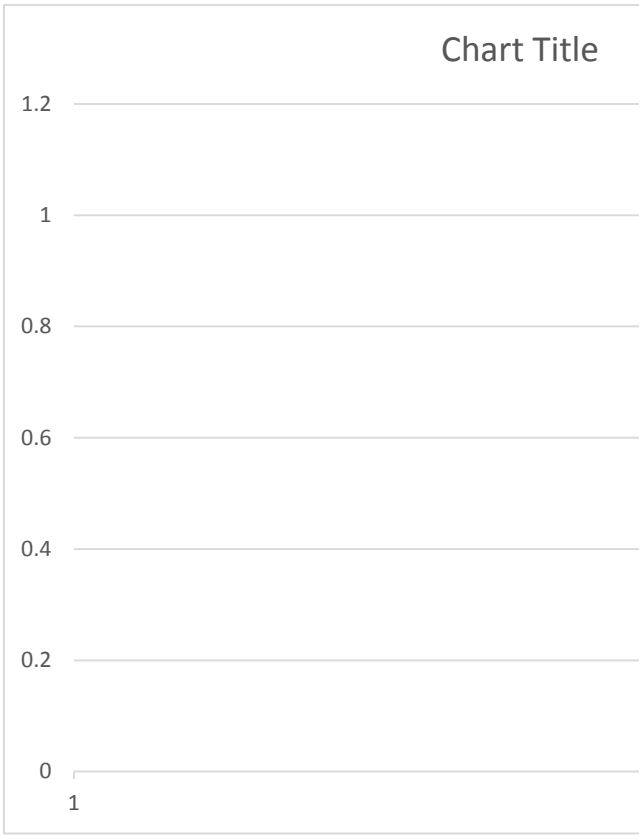


| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 683 | 685 | 671 | 650 | 627 |
| 18,569 | 18,359 | 17,779 | 17,241 | 16,520 |
| ***-1335.34*** | ***-1545.69*** | ***-1762.53*** | ***-1984.85*** | ***-2212.33*** |

| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

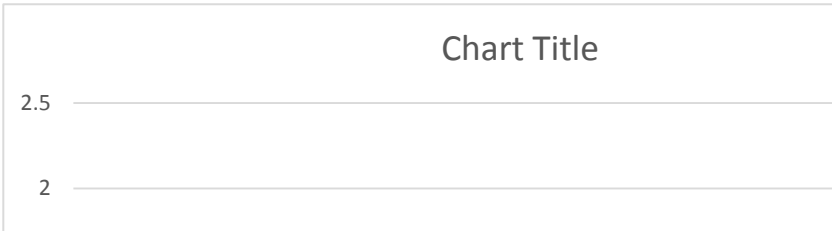


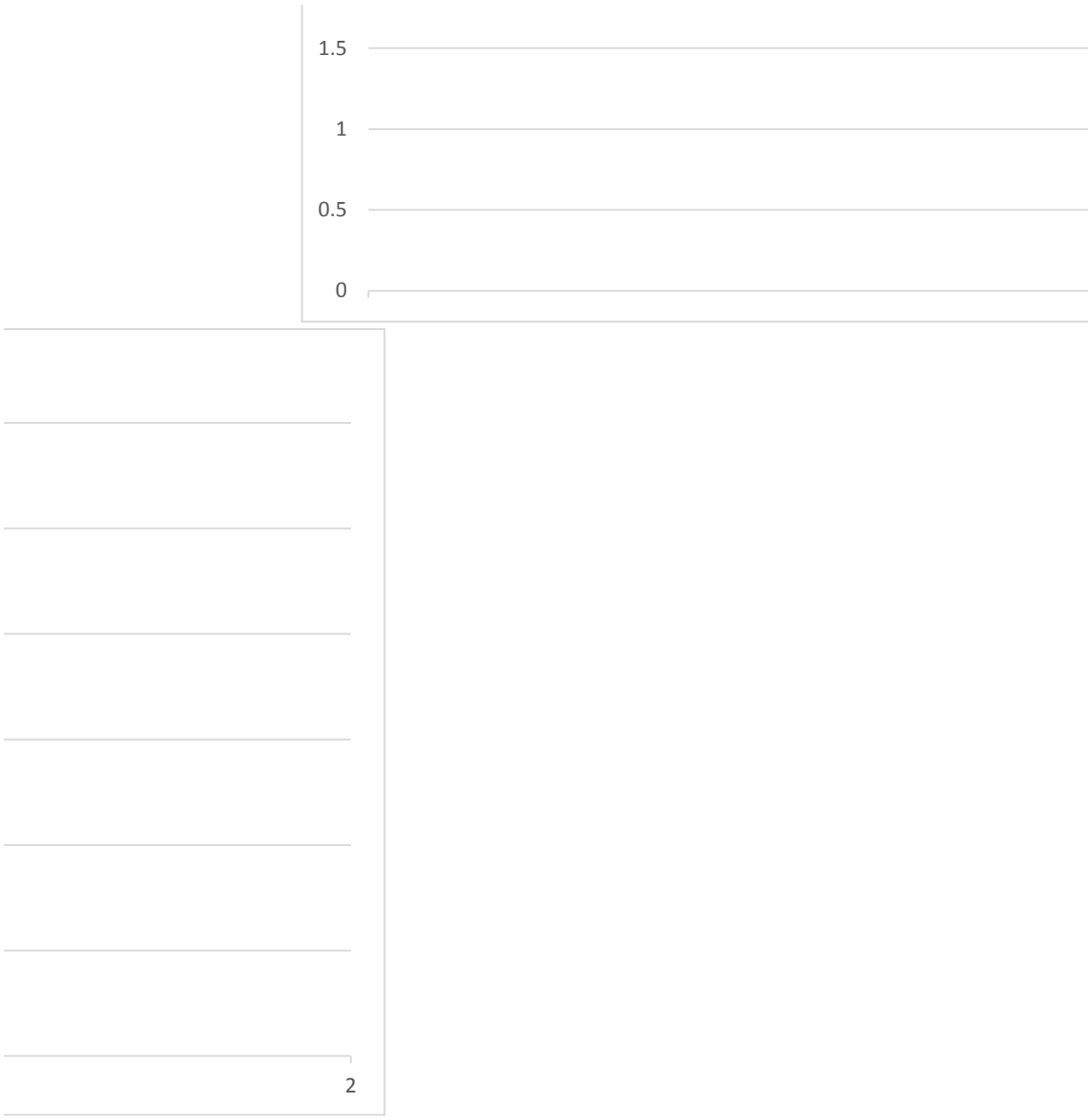
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|---|---|---|---|---|
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| ***-2444.06*** | ***-2677.73*** | ***-2910.37*** | ***-3140.53*** | ***-3367.72*** |


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| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

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| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
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| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |



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|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 60 | 12 | (38) | (94) | (165) |
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| ***-4687.72*** | ***-4906.18*** | ***-5123.72*** | ***-5339.11*** | ***-5549.02*** |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 3.71% | *<-- Change this number to test differ* |
| Basis Points | 00 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 3.7119% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 3.71% | |
| **Year Interest Payments Stop:** | 2045 | |
| **Total Interest Paid:** | 11,368 | *NOTE: Calculations do not match En* |
| **Peak Debt:** | 18,569 | |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 11,368 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |

**WEIGHTED AVERAGE:**

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.712% | |
| FHT Interest Paid | 11,368 | |
| Peak Debt: | 18,569 | |
| | | |
| Provincial Borrowing at Issuance: | 3.20% | *Source: OFA* |
| Provincial Interest Paid: | 8,887 | |
| Peak Debt: | 17,752 | |
| | | |
| **Difference in Interest Paid:** | **2,481** | |
| **Difference in Peak Debt:** | **817** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɪs*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
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| 3.520% | *Source: Debt Issuance Document* |
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| |
|---|
| **3.712%** |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 26 |
| Closing Debt Balance [EFB Calculation] | 1,423 |

***-5.74***

| 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| 116 | 225 | 343 | 466 | 577 |
| 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

3.71%

**2045** *(note: array formula)*

**11,368**

**18,569**

| **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
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| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
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| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

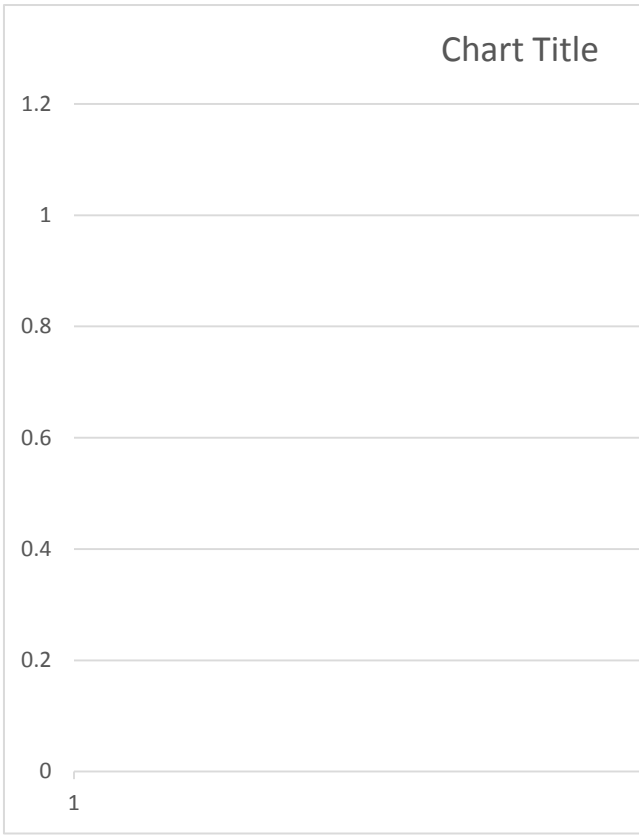


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|---|---|---|---|---|
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| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

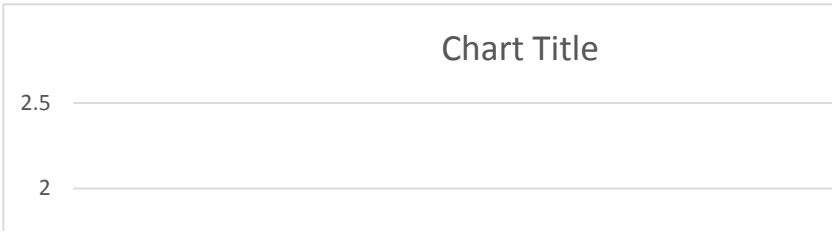


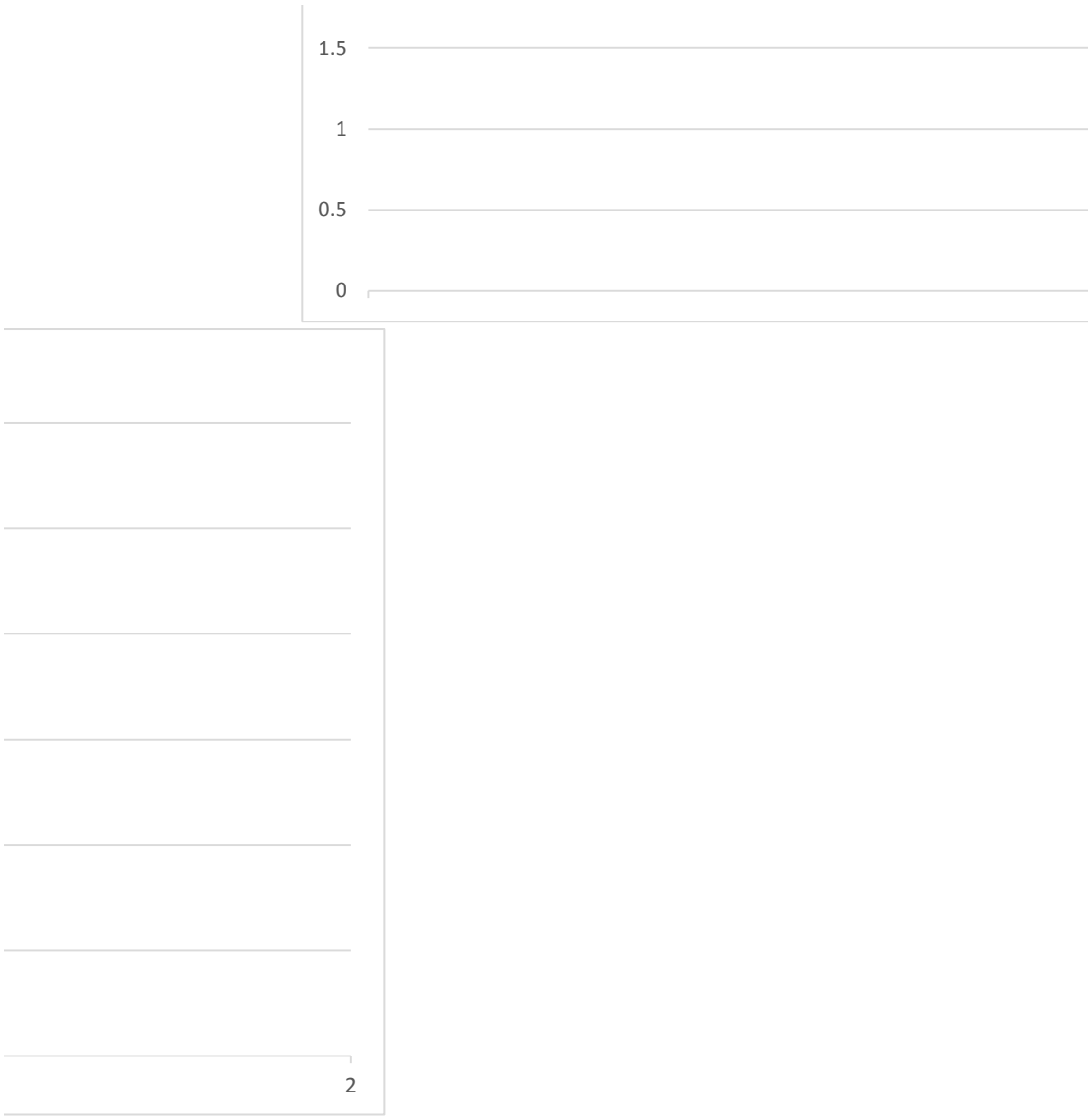
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| Total (Interest Rate) | 3.7119% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

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| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
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*Sensitivites and difference compared to provincial borrowing*

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|---|---|---|
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| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |

**WEIGHTED AVERAGE:**

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.712% | |
| FHT Interest Paid | 11,368 | |
| Peak Debt: | 18,569 | |
| | | |
| Provincial Borrowing at Issuance: | 3.20% | *Source: OFA* |
| Provincial Interest Paid: | 8,887 | |
| Peak Debt: | 17,752 | |
| | | |
| **Difference in Interest Paid:** | **2,481** | |
| **Difference in Peak Debt:** | **817** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɪs*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.520% | *Source: Debt Issuance Document* |
| 3.834% | *Source: Debt Issuance Document* |
| 4.214% | *Source: Debt Issuance Document* |

| |
|---|
| **3.712%** |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 26 |
| Closing Debt Balance [EFB Calculation] | 1,423 |

***-5.74***

| 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|
| (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| 116 | 225 | 343 | 466 | 577 |
| 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

3.71%

**2045** *(note: array formula)*

**11,368**

**18,569**

| **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | Additional Borrowing/F |
| 95 | 184 | 280 | 378 | 466 |
| 3,707 | 6,186 | 8,879 | 11,461 | 13,627 |
| ***-26.68*** | ***-67.79*** | ***-131.64*** | ***-219.70*** | ***-330.96*** |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | Cross Over Point: | (61) | | |
| | Borrrowing Still Required: | | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 535 | 585 | 616 | 639 | 664 |
| 15,212 | 16,289 | 16,905 | 17,544 | 18,207 |
| ***-462.45*** | ***-610.73*** | ***-772.66*** | ***-947.11*** | ***-1134.84*** |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

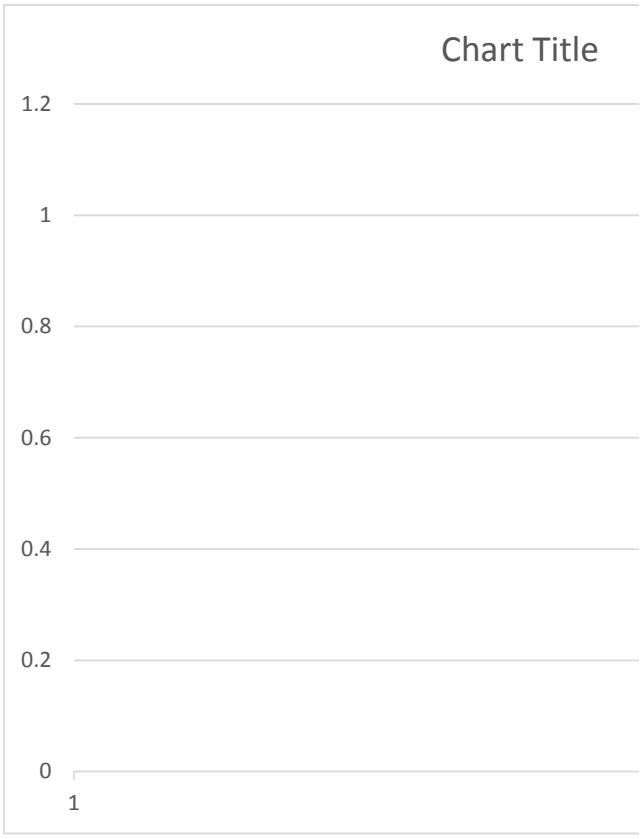


| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 683 | 685 | 671 | 650 | 627 |
| 18,569 | 18,359 | 17,779 | 17,241 | 16,520 |
| ***-1335.34*** | ***-1545.69*** | ***-1762.53*** | ***-1984.85*** | ***-2212.33*** |

| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

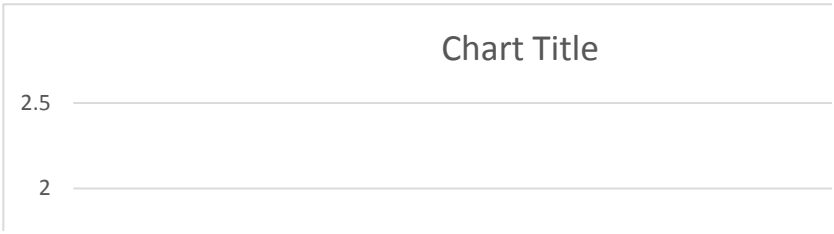


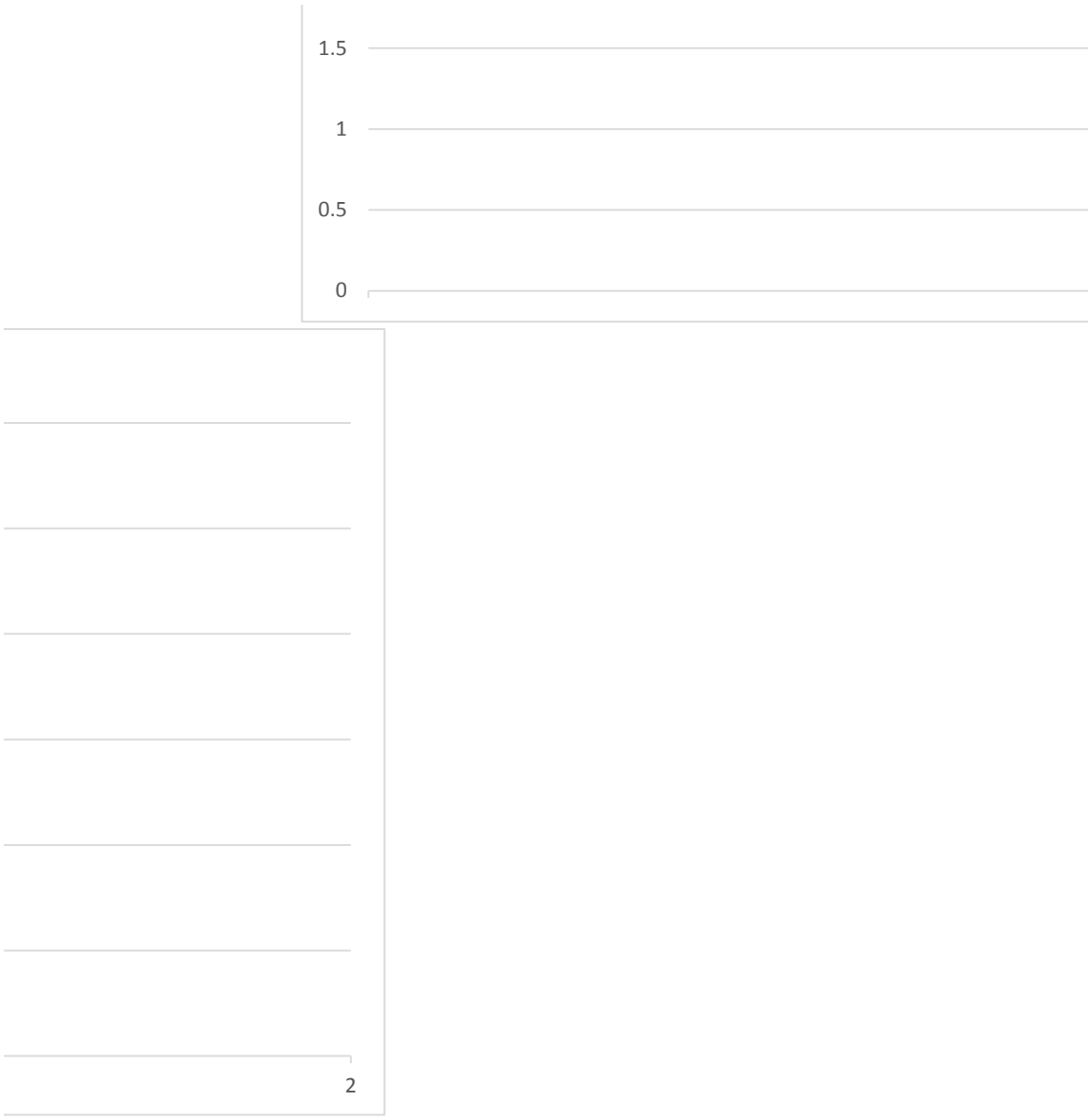
| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 598 | 558 | 503 | 443 | 380 |
| 15,698 | 14,356 | 12,772 | 11,087 | 9,405 |
| ***-2444.06*** | ***-2677.73*** | ***-2910.37*** | ***-3140.53*** | ***-3367.72*** |


Chart Title
1.2
1
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0.4
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1

| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|
| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
| 316 | 254 | 201 | 153 | 107 |
| 7,622 | 6,081 | 4,755 | 3,516 | 2,244 |
| ***-3591.40*** | ***-3811.97*** | ***-4031.14*** | ***-4250.06*** | ***-4468.94*** |




1.5
1
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0
2

| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |



| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 60 | 12 | (38) | (94) | (165) |
| 994 | (335) | (1,730) | (3,350) | (5,549) |
| ***-4687.72*** | ***-4906.18*** | ***-5123.72*** | ***-5339.11*** | ***-5549.02*** |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 4.50% | *<-- Change this number to test differ* |
| Basis Points | 50 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 5.0000% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 5.00% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 21,083 | *NOTE: Calculations do not match En* |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 21,083 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |
| | | **WEIGHTED AVERAGE:** |

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.526% | |
| FHT Interest Paid | 10,399 | |
| | | |
| Provincial Borrowing at Issuance: | 3.12% | *Source: OFA* |
| Provincial Interest Paid | 8,540 | |
| | | |
| **Difference in Interest:** | **1,858** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɨis*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
|---|---|
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.357% | *Source: Debt Issuance* |
| 3.64% | *Source: Email* |
| 3.96% | *Source: Email* |
| **3.526%** | |

**INPUTS:**

| Calculation for Scenario Analysis | |
|---|---|
| Provincial Borrowing | 4.50% |
| Basis Points | 00 bp |
| Total (Interest Rate) | 4.50% |

**OUTPUTS:**

| Interest Calculation | |
|---|---|
| **Interest Rate:** | 4.50% |
| **Year Interest Payments Stop:** | 2047 |
| **Total Interest Paid:** | 14,308 |
| **Peak Debt:** | 17,612 |
| **Annual Paydown Amount:** | (1,278) |

**SCENARIOS:**

| | 3.12% | |
|---|---|---|
| **Interest Rate:** | 3.12% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 9,038 | |
| **Peak Debt:** | 16,348 | |
| **Annual Paydown Amount:** | (1,038) | |
| **Difference in Interest Paid:** | | 1,4 |

## Scenario Analysis with EFB Model

| 3.12% + 40bp | 4.50% | 4.5% + 50bp |
|---|---|---|
| 3.52% | 4.50% | 5.00% |
| 2047 | 2047 | 2047 |
| 10,477 | 14,308 | 16,438 |
| 16,705 | 17,612 | 18,093 |
| (1,104) | (1,278) | (1,375) |
| 39 | 2,130 | |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 36 |
| Closing Debt Balance [EFB Calculation] | 1,432 |

***3.66***

## Attempted recreation and extrapolation by EFB ($ nominal Million)

**Interest:**
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|

| | |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** | |
| ***(Exactly from above)*** | 1,396 |
| *Reduction* | |
| **Opening Debt:** | 0 |
| **IN YEAR ANALYSIS** | |
| **In-Year Interest:** | 29 |
| **In-Year Accumulated Debt (Excl Interest):** | 1,396 |
| **In-Year - End Debt:** | 1,425 |
| **Debt Interest from Prior Year:** | 0 |
| **Total Accumulated Interest:** | 29 |
| **Accumulated Debt:** | 1,396 |
| **Debt Reduction:** | |
| **Closing Debt:** | 1,425 |

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| | 116 | 225 | 343 | 466 | 577 |
| | 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

5.00%
**2047**
**21,083**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|
| | 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | | Additional Borrowing/F |
| | 130 | 251 | 385 | 523 | 650 |
| | 3,751 | 6,297 | 9,096 | 11,823 | 14,173 |
| | ***17.09*** | ***43.57*** | ***84.95*** | ***142.36*** | ***215.40*** |

4.50%
**2047**
**14,308**
**17,612**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 1,425 | 3,724 | 6,235 | 8,980 | 11,634 |
| 46 | 48 | 50 | 46 | 36 |
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 2,235 | 2,344 | 2,464 | 2,250 | 1,736 |
| 64 | 168 | 281 | 404 | 524 |
| 110 | 216 | 331 | 450 | 559 |
| 3,614 | 6,020 | 8,649 | 11,184 | 13,334 |
| 3,724 | 6,235 | 8,980 | 11,634 | 13,894 |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | | Cross Over Point: | (61) | |
| | | Borrrowing Still Required: | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 754 | 832 | 887 | 933 | 981 |
| 15,977 | 17,301 | 18,188 | 19,121 | 20,101 |
| ***302.42*** | ***401.45*** | ***510.70*** | ***629.63*** | ***758.92*** |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1,050 | 492 | 61 | | |
| | | | -1278 | -1278 |
| 13,894 | 15,591 | 16,794 | 17,612 | 17,127 |
| | | | | |
| 22 | 10 | 1 | 0 | 0 |
| 1,050 | 492 | 61 | 0 | 0 |
| 1,072 | 502 | 62 | 0 | 0 |
| | | | | |
| 625 | 702 | 756 | 793 | 771 |
| | | | | |
| 647 | 712 | 757 | 793 | 771 |
| 14,944 | 16,083 | 16,855 | 17,612 | 17,127 |
| | | | (1,278) | (1,278) |
| | | | | |
| 15,591 | 16,794 | 17,612 | 17,127 | 16,620 |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 1,023 | 1,044 | 1,042 | 1,033 | 1,021 |
| 20,803 | 20,951 | 20,743 | 20,588 | 20,262 |
| ***898.48*** | ***1046.63*** | ***1201.44*** | ***1362.46*** | ***1529.65*** |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|

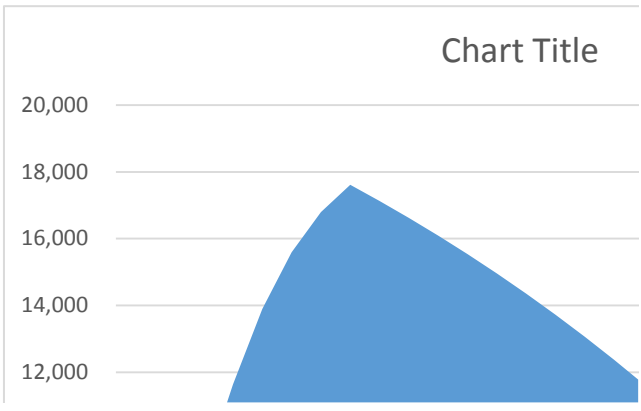
| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 748 | 724 | 699 | 673 | 646 |
| 748 | 724 | 699 | 673 | 646 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 16,090 | 15,537 | 14,958 | 14,354 | 13,722 |

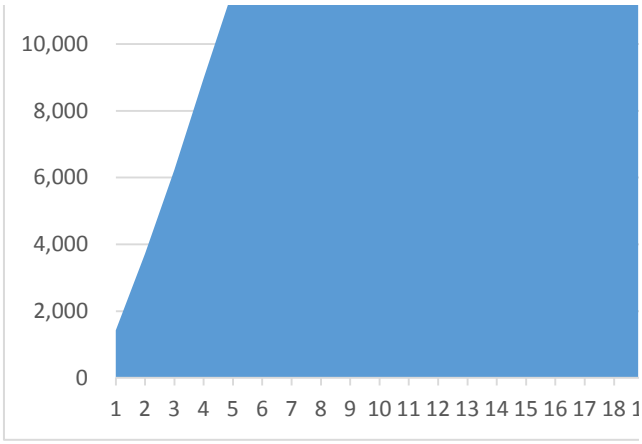
| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 1,003 | 969 | 916 | 855 | 792 |
| 19,845 | 18,913 | 17,743 | 16,470 | 15,200 |
| ***1702.65*** | ***1880.16*** | ***2060.46*** | ***2242.82*** | ***2427.07*** |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 617 | 588 | 557 | 524 | 490 |
| 617 | 588 | 557 | 524 | 490 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 13,062 | 12,372 | 11,651 | 10,897 | 10,110 |




10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 1

| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

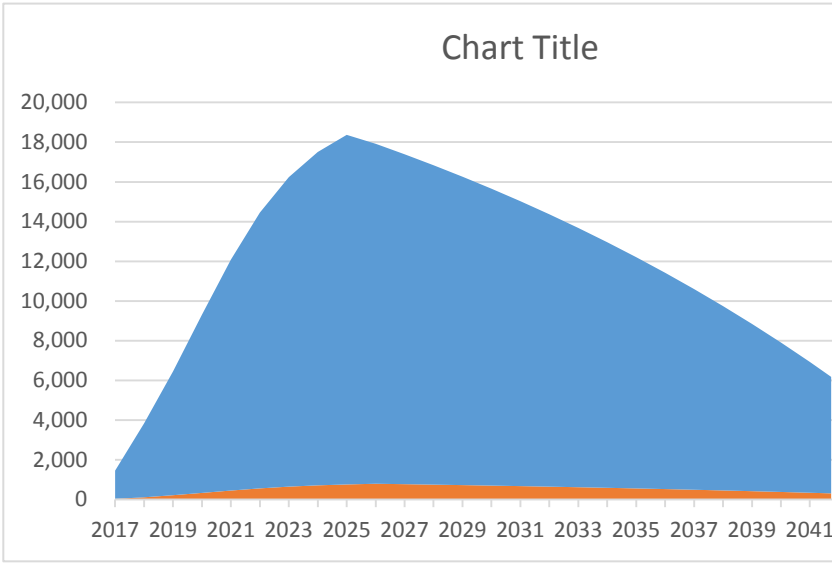


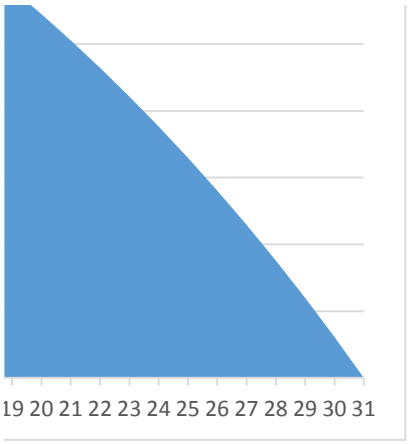
| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|
| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
| 726 | 663 | 612 | 568 | 526 |
| 13,827 | 12,694 | 11,779 | 10,955 | 10,102 |
| ***2613.03*** | ***2801.15*** | ***2992.70*** | ***3188.61*** | ***3389.25*** |



| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 455 | 418 | 379 | 339 | 297 |
| 455 | 418 | 379 | 339 | 297 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 9,287 | 8,427 | 7,529 | 6,590 | 5,609 |




19 20 21 22 23 24 25 26 27 28 29 30 31

| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |

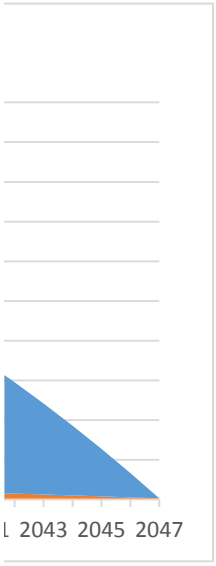


| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 484 | 441 | 395 | 341 | 267 |
| 9,277 | 8,377 | 7,415 | 6,230 | 4,464 |
| ***3594.84*** | ***3805.48*** | ***4021.06*** | ***4241.07*** | ***4463.66*** |



| **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) | (2,613) |



| 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) | (17,685) |

| 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 |
|---|---|---|---|---|---|---|

| | |
|---|---|
| -1278 | -1278 |
| | |
| (17,685) | (19,758) |
| | |
| | |
| 0 | 0 |
| 0 | 0 |
| 0 | 0 |
| | |
| (796) | (889) |
| | |
| (796) | (889) |
| (17,685) | (19,758) |
| (1,278) | (1,278) |
| | |
| (19,758) | (21,925) |

**Instructions: An updated projection of the annual cost of the refinancing portion of the Fa**

**Please contact Matt Gurham (mgurham@fao-on.org) if assistance is required.**

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayment Amount Cash Flows**

| *$ millions* |
|---|
| IESO forecast Global Adjustment cost * |
| Global Adjustment payment from ratepayer ** |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for all customers (2017-203
** Represents total OFHP costs recovered from consumers, including deferral of GA and recovery of

**Provincial Actual and Projected Fair Hydro Plan Debt**

| *$ millions* |
|---|
| Amount borrowed/paid-back in given year*** |
| Interest**** ~~on accumulated debt from previous year~~ |
| Accumulated Debt |

***Values represent deferral of GA costs and recovery of principal.
****Interest is calculated based on the average debt balance for the year and a 5 per cent interest ra
This data was used to inform the Minister's letter to OPG.

**OPG Actual and Projected Fair Hydro Plan Debt**

| *$ million* |
|---|
| Amount borrowed/paid-back in given year |
| Interest on accumulated debt from previous year |
| Accumulated Debt |

## Equity Injection Comparisons

Revised Annual Borrowings
Equity Injection (44%)

Revised Equity Injections - Fiscalized
EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)
Variance

## IOD Comparisons

***Revised Equity Injections - Fiscalized***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

***EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

**Variance in IOD Impacts**

**ıir Hydro Plan.**

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 10,078 | 10,144 | 10,801 | 10,576 | 9,671 | 9,471 | 8,733 |
| 8,682 | 7,955 | 8,505 | 8,162 | 7,467 | 7,771 | 7,683 |

:5) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by assuming 2% CPI
principal, interest and fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| -1,448 | -2,322 | -2,553 | -2,808 | -2,740 | -2,363 | -1,819 |
| 52 | 133 | 257 | 394 | 536 | 663 | 769 |
| 1,448 | 3,770 | 6,323 | 9,131 | 11,871 | 14,234 | 16,053 |

ate over the 30-year life of the program, and includes associated fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 1,448 | 2,322 | 2,553 | 2,808 | 2,740 | 2,363 | 1,819 |
| 637 | 1022 | 1123 | 1235 | 1206 | 1040 | 800 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 |
|---|---|---|---|---|---|---|
| 893 | 1047 | 1151 | 1228 | 1164 | 980 | 748 |
| 853 | 979 | 1023 | 1035 | 911 | 675 | 402 |
| 40 | 69 | 128 | 193 | 253 | 305 | 346 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|
| 893 | 1,047 | 1,151 | 1,228 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 11 | 21 | 21 | 21 |
| | 18 | 35 | 35 |
| | | 23 | 46 |
| | | | 27 |
| **11** | **39** | **80** | **130** |
| | | | |
| 853 | 979 | 1,023 | 1,035 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 10 | 20 | 20 | 20 |
| | 16 | 33 | 33 |
| | | 21 | 41 |
| | | | 23 |
| **10** | **37** | **74** | **117** |
| | | | |
| **0** | **2** | **6** | **13** |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 9,917 | 8,924 | 9,908 | 10,169 | 10,300 | 9,978 | 9,472 |
| 9,425 | 8,924 | 9,908 | 10,169 | 11,297 | 11,009 | 10,877 |

and extrapolated post-2035 based on the average rate of change between 2026-2035.

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| -1,342 | -907 | -954 | -1,004 | -33 | 0 | 385 |
| 850 | 907 | 954 | 1,004 | 1,030 | 1,031 | 1,021 |
| 17,395 | 18,301 | 19,255 | 20,259 | 20,292 | 20,292 | 19,907 |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 1,342 | 907 | 954 | 1,004 | 33 | 0 | -385 |
| 590 | 399 | 420 | 442 | 15 | 0 | -169 |

| 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 |
|---|---|---|---|---|---|---|
| 542 | 404 | 425 | 335 | 11 | -42 | -164 |
| 152 | -51 | -112 | -159 | -270 | -444 | -604 |
| 390 | 455 | 537 | 494 | 281 | 402 | 440 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 | 4,771 | 4,417 | 4,089 |
| 9,789 | 9,840 | 9,009 | 8,291 | 6,988 | 6,666 | 6,262 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 337 | 515 | 611 | 1,131 | 1,372 | 1,477 | 1,476 |
| 1,003 | 981 | 952 | 908 | 845 | 772 | 697 |
| 19,570 | 19,055 | 18,444 | 17,313 | 15,941 | 14,464 | 12,988 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| -337 | -515 | -611 | -1,131 | -1,372 | -1,477 | -1,476 |
| -148 | -227 | -269 | -498 | -604 | -650 | -650 |

| 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 |
|---|---|---|---|---|---|---|
| -168 | -237 | -326 | -524 | -615 | -650 | -661 |
| -609 | -664 | -745 | -913 | -977 | -980 | -960 |
| 442 | 427 | 419 | 389 | 362 | 330 | 299 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 3,785 | 3,504 | 3,244 | 3,003 | 2,780 | 2,574 | 2,383 |
| 5,985 | 5,392 | 4,855 | 4,474 | 4,230 | 3,948 | 3,780 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 1,580 | 1,343 | 1,128 | 1,041 | 1,075 | 1,053 | 1,132 |
| 620 | 545 | 483 | 429 | 375 | 321 | 265 |
| 11,408 | 10,065 | 8,937 | 7,895 | 6,821 | 5,768 | 4,636 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| -1,580 | -1,343 | -1,128 | -1,041 | -1,075 | -1,053 | -1,132 |
| -695 | -591 | -496 | -458 | -473 | -463 | -498 |

| 2038-39 | 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 |
|---|---|---|---|---|---|---|
| -669 | -567 | -487 | -462 | -470 | -472 | -505 |
| -930 | -801 | -695 | -646 | -629 | -608 | -615 |
| 261 | 234 | 208 | 184 | 159 | 137 | 110 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 2,206 | 2,042 | 1,891 | 1,750 |
| 3,611 | 3,608 | 3,952 | 1,750 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 1,199 | 1,427 | 2,010 | 0 |
| 206 | 139 | 51 | 0 |
| 3,437 | 2,010 | 0 | 0 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| -1,199 | -1,427 | -2,010 | 0 |
| -528 | -628 | -885 | 0 |

| 2045-46 | 2046-47 | 2047-48 |
|---|---|---|
| -553 | -692 | -663 |
| -637 | -748 | -675 |
| 85 | 56 | 11 |

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayme**

| *$ millions* | **2017** | **2018** |
|---|---|---|
| IESO forecast Global A | 10,078 | 10,144 |
| Global Adjustment pay | 8,682 | 7,955 |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for a
** Represents total OFHP costs recovered from consumers, including deferral

| | | |
|---|---|---|
| Deferral | 1,396 | 2,189 |
| | 52 | 133 |
| Annual Borrowings | 1,448 | 2,322 |
| TOTAL | 1,448 | 3,770 |
| | | |
| | 0.03719145 | 0.060789592 |
| | 0.035857845 | 0.035294613 |
| | 0.03719145 | 0.036585899 |
| | 0.0358578446 | 0.0510000000 |
| | 0.0371914498 | 0.0537407798 |
| | 0.0371914498 | 0.0523345305 |
| | | |
| | 5% | |
| | | |
| Recalculation | 1,396 | 2,189 |
| | 52 | 130 |
| | 1,448 | 2,319 |
| | 1,448 | 3,768 |

**nt Amount Cash Flows**

| 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|
| 10,801 | 10,576 | 9,671 | 9,471 |
| 8,505 | 8,162 | 7,467 | 7,771 |

ll customers (2017-2035) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by
of GA and recovery of principal, interest and fees.

| | | | |
|---|---|---|---|
| 2,296 | 2,414 | 2,204 | 1,700 |
| 257 | 394 | 536 | 663 |
| 2,553 | 2,808 | 2,740 | 2,363 |
| 6,323 | 9,131 | 11,871 | 14,234 |
| | | | |
| 0.112122144 | 0.163279846 | 0.242946991 | 0.390032973 |
| 0.040704571 | 0.043159126 | 0.045114332 | 0.046583166 |
| 0.042431736 | 0.045105856 | 0.047245794 | 0.048859181 |
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0508000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0535187526 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0521239483 |
| | 0.050837963 | | |
| | | | |
| 2,296 | 2,414 | 2,204 | 1,700 |
| 252 | 386 | 524 | 651 |
| 2,548 | 2,799 | 2,728 | 2,351 |
| 6,315 | 9,115 | 11,843 | 14,194 |

| 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|
| 8,733 | 9,917 | 8,924 | 9,908 |
| 7,683 | 9,425 | 8,924 | 9,908 |

y assuming 2% CPI and extrapolated post-2035 based on the average rate of change between 2026-2035.

| | | | |
|---|---|---|---|
| 1,050 | 492 | 0 | 0 |
| 769 | 850 | 907 | 954 |
| 1,819 | 1,342 | 907 | 954 |
| 16,053 | 17,395 | 18,301 | 19,255 |
| | | | |
| 0.73265484 | 1.72677531 | #DIV/0! | #DIV/0! |
| 0.047921434 | 0.048841011 | 0.049541642 | 0.049541642 |
| 0.050333487 | 0.051348946 | 0.052123948 | 0.052123948 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 1,050 | 492 | 0 | 0 |
| 755 | 833 | 888 | 934 |
| 1,805 | 1,325 | 888 | 934 |
| 15,999 | 17,324 | 18,212 | 19,146 |

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| 10,169 | 10,300 | 9,978 | 9,472 |
| 10,169 | 11,297 | 11,009 | 10,877 |

| | | | |
|---|---|---|---|
| 0 | -997 | -1,031 | -1,406 |
| 1,004 | 1,030 | 1,031 | 1,021 |
| 1,004 | 33 | 0 | -385 |
| 20,259 | 20,292 | 20,292 | 19,907 |
| | | | |
| #DIV/0! | -1.033303874 | -1 | -0.726329513 |
| | | | |
| 0.052123948 | 0.053472634 | 0.053518753 | 0.054063854 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 0 | -997 | -1,031 | -1,406 |
| 982 | 1007 | 1006 | 995 |
| 982 | 10 | -25 | -410 |
| 20,128 | 20,138 | 20,113 | 19,703 |

| 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 |
| 9,789 | 9,840 | 9,009 | 8,291 |

| | | | |
|---|---|---|---|
| -1,340 | -1,496 | -1,564 | -2,039 |
| 1,003 | 981 | 952 | 908 |
| -337 | -515 | -611 | -1,131 |
| 19,570 | 19,055 | 18,444 | 17,313 |
| | | | |
| -0.748423197 | -0.655724615 | -0.609140601 | |
| | | | |
| 0.054004521 | 0.054281378 | 0.054453742 | 0.055363212 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| -1,340 | -1,496 | -1,564 | -2,039 |
| 976 | 953 | 924 | 879 |
| -364 | -543 | -640 | -1,160 |
| 19,339 | 18,796 | 18,156 | 16,996 |

| 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|
| 4,771 | 4,417 | 4,089 | 3,785 |
| 6,988 | 6,666 | 6,262 | 5,985 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 845 | 772 | 697 | 620 |
| -1,372 | -1,477 | -1,476 | -1,580 |
| 15,941 | 14,464 | 12,988 | 11,408 |

| | | | |
|---|---|---|---|
| 0.055951526 | | | |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 815 | 742 | 667 | 589 |
| -1,402 | -1,507 | -1,507 | -1,611 |
| 15,594 | 14,087 | 12,580 | 10,968 |

| 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|
| 3,504 | 3,244 | 3,003 | 2,780 |
| 5,392 | 4,855 | 4,474 | 4,230 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 545 | 483 | 429 | 375 |
| -1,343 | -1,128 | -1,041 | -1,075 |
| 10,065 | 8,937 | 7,895 | 6,821 |

| | | | |
|---|---|---|---|
| 0.0508000000 | 0.0508000000 | 0.0510000000 | 0.0510000000 |
| 0.0535187526 | 0.0535187526 | 0.0537407798 | 0.0537407798 |
| 0.0521239483 | 0.0521239483 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 514 | 451 | 395 | 340 |
| -1,374 | -1,160 | -1,076 | -1,110 |
| 9,595 | 8,434 | 7,358 | 6,249 |

| 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|
| 2,574 | 2,383 | 2,206 | 2,042 |
| 3,948 | 3,780 | 3,611 | 3,608 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 321 | 265 | 206 | 139 |
| -1,053 | -1,132 | -1,199 | -1,427 |
| 5,768 | 4,636 | 3,437 | 2,010 |

| | | | |
|---|---|---|---|
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0510000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0537407798 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 285 | 229 | 169 | 101 |
| -1,088 | -1,168 | -1,236 | -1,464 |
| 5,160 | 3,992 | 2,756 | 1,291 |

| 2047 | 2048 |
|---|---|
| 1,891 | 1,750 |
| 3,952 | 1,750 |

| | |
|---|---|
| -2,062 | 0 |
| 51 | 0 |
| -2,010 | 0 |
| 0 | 0 |

| | |
|---|---|
| 0.0510000000 | 0.0000000000 |
| 0.0537407798 | 0.0000000000 |
| 0.0523345305 | 0.0000000000 |

| | |
|---|---|
| -2,062 | 0 |
| 13 | -39 |
| -2,048 | -39 |
| -757 | -796 |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 4.50% | *<-- Change this number to test differ* |
| Basis Points | 50 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 5.0000% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 5.00% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 21,083 | *NOTE: Calculations do not match En* |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 21,083 | 0 bp | 30 bp |
| 3.12% | 8,542 | 9,885 |
| 3.50% | 10,275 | 11,857 |
| 3.75% | 11,578 | 13,362 |
| 4.00% | 13,047 | 15,075 |
| 4.25% | 14,716 | 17,030 |
| 4.50% | 16,619 | 19,200 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | 1,343 |
| 3.50% | - | 1,582 |
| 3.75% | - | 1,784 |
| 4.00% | - | 2,028 |
| 4.25% | - | 2,314 |
| 4.50% | - | 2,580 |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |
| | | **WEIGHTED AVERAGE:** |

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.526% | |
| FHT Interest Paid | 10,399 | |
| | | |
| Provincial Borrowing at Issuance: | 3.12% | *Source: OFA* |
| Provincial Interest Paid | 8,540 | |
| | | |
| **Difference in Interest:** | **1,858** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɨis*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
|---|---|
| 10,374 | 10,879 |
| 12,432 | 13,047 |
| 14,017 | 14,716 |
| 15,821 | 16,619 |
| 17,874 | 18,750 |
| 20,124 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 1,832 | 2,337 |
| 2,156 | 2,771 |
| 2,439 | 3,138 |
| 2,774 | 3,573 |
| 3,158 | 4,034 |
| 3,505 | 4,464 |

| ation | |
|---|---|
| 3.357% | *Source: Debt Issuance* |
| 3.64% | *Source: Email* |
| 3.96% | *Source: Email* |
| **3.526%** | |

**INPUTS:**

| Calculation for Scenario Analysis | |
|---|---|
| Provincial Borrowing | 4.50% |
| Basis Points | 00 bp |
| Total (Interest Rate) | 4.50% |

**OUTPUTS:**

| Interest Calculation | |
|---|---|
| **Interest Rate:** | 4.50% |
| **Year Interest Payments Stop:** | 2047 |
| **Total Interest Paid:** | 14,308 |
| **Peak Debt:** | 17,612 |
| **Annual Paydown Amount:** | (1,278) |

**SCENARIOS:**

| | 3.12% | |
|---|---|---|
| **Interest Rate:** | 3.12% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 9,038 | |
| **Peak Debt:** | 16,348 | |
| **Annual Paydown Amount:** | (1,038) | |
| **Difference in Interest Paid:** | | 1,4 |

## Scenario Analysis with EFB Model

| 3.12% + 40bp | 4.50% | 4.5% + 50bp |
|---|---|---|
| 3.52% | 4.50% | 5.00% |
| 2047 | 2047 | 2047 |
| 10,477 | 14,308 | 16,438 |
| 16,705 | 17,612 | 18,093 |
| (1,104) | (1,278) | (1,375) |
| 39 | 2,130 | |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 36 |
| Closing Debt Balance [EFB Calculation] | 1,432 |

***3.66***

## Attempted recreation and extrapolation by EFB ($ nominal Million)

**Interest:**
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|

| | |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** | |
| ***(Exactly from above)*** | 1,396 |
| *Reduction* | |
| **Opening Debt:** | 0 |
| **IN YEAR ANALYSIS** | |
| **In-Year Interest:** | 29 |
| **In-Year Accumulated Debt (Excl Interest):** | 1,396 |
| **In-Year - End Debt:** | 1,425 |
| **Debt Interest from Prior Year:** | 0 |
| **Total Accumulated Interest:** | 29 |
| **Accumulated Debt:** | 1,396 |
| **Debt Reduction:** | |
| **Closing Debt:** | 1,425 |

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| | 116 | 225 | 343 | 466 | 577 |
| | 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

5.00%
**2047**
**21,083**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|
| | 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | | Additional Borrowing/F |
| | 130 | 251 | 385 | 523 | 650 |
| | 3,751 | 6,297 | 9,096 | 11,823 | 14,173 |
| | ***17.09*** | ***43.57*** | ***84.95*** | ***142.36*** | ***215.40*** |

4.50%
**2047**
**14,308**
**17,612**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 1,425 | 3,724 | 6,235 | 8,980 | 11,634 |
| 46 | 48 | 50 | 46 | 36 |
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 2,235 | 2,344 | 2,464 | 2,250 | 1,736 |
| 64 | 168 | 281 | 404 | 524 |
| 110 | 216 | 331 | 450 | 559 |
| 3,614 | 6,020 | 8,649 | 11,184 | 13,334 |
| 3,724 | 6,235 | 8,980 | 11,634 | 13,894 |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | | Cross Over Point: | (61) | |
| | | Borrrowing Still Required: | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 754 | 832 | 887 | 933 | 981 |
| 15,977 | 17,301 | 18,188 | 19,121 | 20,101 |
| ***302.42*** | ***401.45*** | ***510.70*** | ***629.63*** | ***758.92*** |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1,050 | 492 | 61 | | |
| | | | -1278 | -1278 |
| 13,894 | 15,591 | 16,794 | 17,612 | 17,127 |
| | | | | |
| 22 | 10 | 1 | 0 | 0 |
| 1,050 | 492 | 61 | 0 | 0 |
| 1,072 | 502 | 62 | 0 | 0 |
| | | | | |
| 625 | 702 | 756 | 793 | 771 |
| | | | | |
| 647 | 712 | 757 | 793 | 771 |
| 14,944 | 16,083 | 16,855 | 17,612 | 17,127 |
| | | | (1,278) | (1,278) |
| | | | | |
| 15,591 | 16,794 | 17,612 | 17,127 | 16,620 |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 1,023 | 1,044 | 1,042 | 1,033 | 1,021 |
| 20,803 | 20,951 | 20,743 | 20,588 | 20,262 |
| ***898.48*** | ***1046.63*** | ***1201.44*** | ***1362.46*** | ***1529.65*** |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|

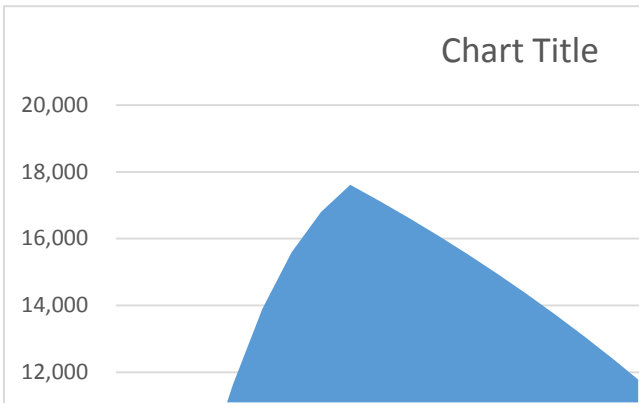
| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 748 | 724 | 699 | 673 | 646 |
| 748 | 724 | 699 | 673 | 646 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 16,090 | 15,537 | 14,958 | 14,354 | 13,722 |

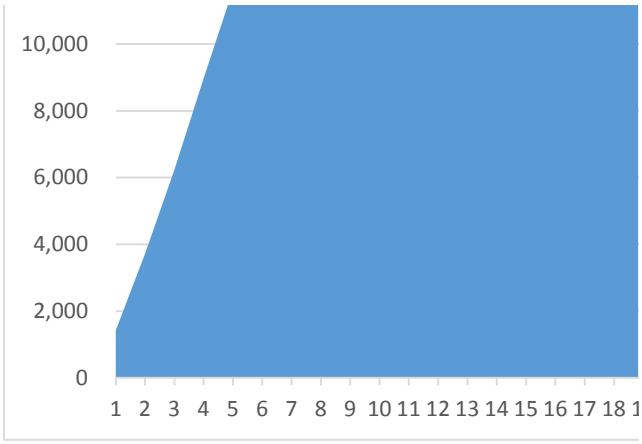
| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 1,003 | 969 | 916 | 855 | 792 |
| 19,845 | 18,913 | 17,743 | 16,470 | 15,200 |
| ***1702.65*** | ***1880.16*** | ***2060.46*** | ***2242.82*** | ***2427.07*** |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 617 | 588 | 557 | 524 | 490 |
| 617 | 588 | 557 | 524 | 490 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 13,062 | 12,372 | 11,651 | 10,897 | 10,110 |




10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 1

| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

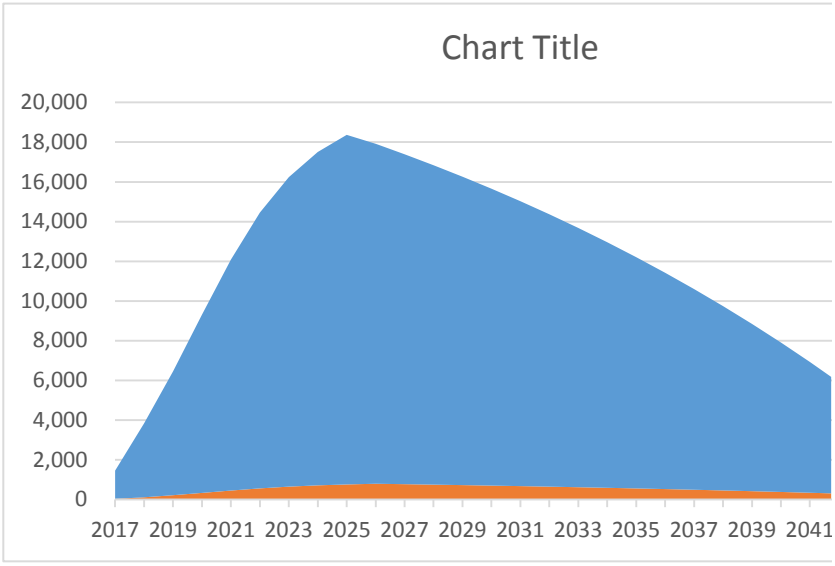


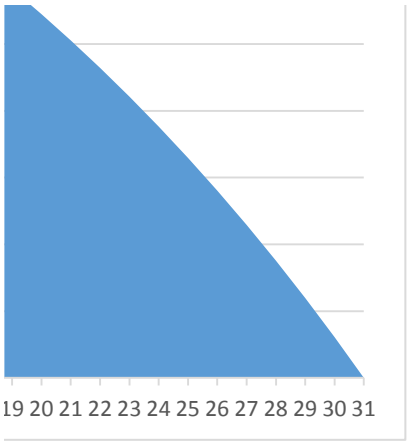
| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|
| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
| 726 | 663 | 612 | 568 | 526 |
| 13,827 | 12,694 | 11,779 | 10,955 | 10,102 |
| ***2613.03*** | ***2801.15*** | ***2992.70*** | ***3188.61*** | ***3389.25*** |



| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 455 | 418 | 379 | 339 | 297 |
| 455 | 418 | 379 | 339 | 297 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 9,287 | 8,427 | 7,529 | 6,590 | 5,609 |




19 20 21 22 23 24 25 26 27 28 29 30 31

| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |

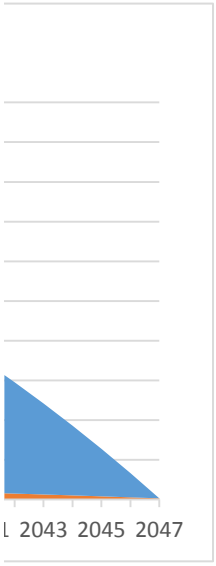


| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 484 | 441 | 395 | 341 | 267 |
| 9,277 | 8,377 | 7,415 | 6,230 | 4,464 |
| ***3594.84*** | ***3805.48*** | ***4021.06*** | ***4241.07*** | ***4463.66*** |



| **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) | (2,613) |



| 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) | (17,685) |

| 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 |
|---|---|---|---|---|---|---|

| | |
|---|---|
| -1278 | -1278 |
| | |
| (17,685) | (19,758) |
| | |
| | |
| 0 | 0 |
| 0 | 0 |
| 0 | 0 |
| | |
| (796) | (889) |
| | |
| (796) | (889) |
| (17,685) | (19,758) |
| (1,278) | (1,278) |
| | |
| (19,758) | (21,925) |

**Instructions: An updated projection of the annual cost of the refinancing portion of the Fa**

**Please contact Matt Gurham (mgurham@fao-on.org) if assistance is required.**

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayment Amount Cash Flows**

| *$ millions* |
|---|
| IESO forecast Global Adjustment cost * |
| Global Adjustment payment from ratepayer ** |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for all customers (2017-203
** Represents total OFHP costs recovered from consumers, including deferral of GA and recovery of

**Provincial Actual and Projected Fair Hydro Plan Debt**

| *$ millions* |
|---|
| Amount borrowed/paid-back in given year*** |
| Interest**** ~~on accumulated debt from previous year~~ |
| Accumulated Debt |

***Values represent deferral of GA costs and recovery of principal.
****Interest is calculated based on the average debt balance for the year and a 5 per cent interest ra
This data was used to inform the Minister's letter to OPG.

**OPG Actual and Projected Fair Hydro Plan Debt**

| *$ million* |
|---|
| Amount borrowed/paid-back in given year |
| Interest on accumulated debt from previous year |
| Accumulated Debt |

## Equity Injection Comparisons

Revised Annual Borrowings
Equity Injection (44%)

Revised Equity Injections - Fiscalized
EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)
Variance

## IOD Comparisons

***Revised Equity Injections - Fiscalized***

OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
2021-22
2022-23
2023-24
2024-25
2025-26
2026-27
2027-28
2028-29

**Total Estimated IOD Impact**

***EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)***

OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21

**Total Estimated IOD Impact**

**Variance in IOD Impacts**

**ıir Hydro Plan.**

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 10,078 | 10,144 | 10,801 | 10,576 | 9,671 | 9,471 | 8,733 |
| 8,682 | 7,955 | 8,505 | 8,162 | 7,467 | 7,771 | 7,683 |

:5) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by assuming 2% CPI
principal, interest and fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| -1,448 | -2,322 | -2,553 | -2,808 | -2,740 | -2,363 | -1,819 |
| 52 | 133 | 257 | 394 | 536 | 663 | 769 |
| 1,448 | 3,770 | 6,323 | 9,131 | 11,871 | 14,234 | 16,053 |

ate over the 30-year life of the program, and includes associated fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 1,448 | 2,322 | 2,553 | 2,808 | 2,740 | 2,363 | 1,819 |
| 637 | 1022 | 1123 | 1235 | 1206 | 1040 | 800 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 |
|---|---|---|---|---|---|---|
| 893 | 1047 | 1151 | 1228 | 1164 | 980 | 748 |
| 853 | 979 | 1023 | 1035 | 911 | 675 | 402 |
| 40 | 69 | 128 | 193 | 253 | 305 | 346 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | | | |
|---|---|---|---|---|---|---|
| 893 | 1,047 | 1,151 | 1,228 | 1,164 | 980 | 748 |
| rrowing Rate | OEP | OEP | 20-Year Average | | | |
| 2.4% | 3.4% | 4.0% | 4.4% | 4.4% | 4.4% | 4.4% |
| | | | | | | |
| 11 | 21 | 21 | 21 | 21 | 21 | 21 |
| | 18 | 35 | 35 | 35 | 35 | 35 |
| | | 23 | 46 | 46 | 46 | 46 |
| | | | 27 | 54 | 54 | 54 |
| | | | | 26 | 51 | 51 |
| | | | | | 22 | 43 |
| | | | | | | 16 |
| | | | | | | |
| **11** | **39** | **80** | **130** | **183** | **230** | **268** |
| | | | | | | |
| 853 | 979 | 1,023 | 1,035 | | | |
| rrowing Rate | OEP | OEP | 20-Year Average | | | |
| 2.4% | 3.4% | 4.0% | 4.4% | | | |
| | | | | | | |
| 10 | 20 | 20 | 20 | | | |
| | 16 | 33 | 33 | | | |
| | | 21 | 41 | | | |
| | | | 23 | | | |
| **10** | **37** | **74** | **117** | | | |
| | | | | | | |
| **0** | **2** | **6** | **13** | | | |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 9,917 | 8,924 | 9,908 | 10,169 | 10,300 | 9,978 | 9,472 |
| 9,425 | 8,924 | 9,908 | 10,169 | 11,297 | 11,009 | 10,877 |

and extrapolated post-2035 based on the average rate of change between 2026-2035.

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| -1,342 | -907 | -954 | -1,004 | -33 | 0 | 385 |
| 850 | 907 | 954 | 1,004 | 1,030 | 1,031 | 1,021 |
| 17,395 | 18,301 | 19,255 | 20,259 | 20,292 | 20,292 | 19,907 |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 1,342 | 907 | 954 | 1,004 | 33 | 0 | -385 |
| 590 | 399 | 420 | 442 | 15 | 0 | -169 |

| 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 |
|---|---|---|---|---|---|---|
| 542 | 404 | 425 | 335 | 11 | -42 | -164 |
| 152 | -51 | -112 | -159 | -270 | -444 | -604 |
| 390 | 455 | 537 | 494 | 281 | 402 | 440 |
| | | | | | | |
| 542 | 404 | 425 | 335 | 11 | (42) | (164) |
| 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% |
| | | | | | | |
| 21 | 21 | 21 | 21 | 21 | 21 | |
| 35 | 35 | 35 | 35 | 35 | 35 | |
| 46 | 46 | 46 | 46 | 46 | 46 | |
| 54 | 54 | 54 | 54 | 54 | 54 | |
| 51 | 51 | 51 | 51 | 51 | 51 | |
| 43 | 43 | 43 | 43 | 43 | 43 | |
| 33 | 33 | 33 | 33 | 33 | 33 | |
| 12 | 24 | 24 | 24 | 24 | 24 | |
| | 9 | 18 | 18 | 18 | 18 | |
| | | 9 | 19 | 19 | 19 | |
| | | | 7 | 15 | 15 | |
| | | | | 0 | 0 | |
| **297** | **318** | **336** | **353** | **360** | **360** | |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 | 4,771 | 4,417 | 4,089 |
| 9,789 | 9,840 | 9,009 | 8,291 | 6,988 | 6,666 | 6,262 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 337 | 515 | 611 | 1,131 | 1,372 | 1,477 | 1,476 |
| 1,003 | 981 | 952 | 908 | 845 | 772 | 697 |
| 19,570 | 19,055 | 18,444 | 17,313 | 15,941 | 14,464 | 12,988 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| -337 | -515 | -611 | -1,131 | -1,372 | -1,477 | -1,476 |
| -148 | -227 | -269 | -498 | -604 | -650 | -650 |

| 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 |
|---|---|---|---|---|---|---|
| -168 | -237 | -326 | -524 | -615 | -650 | -661 |
| -609 | -664 | -745 | -913 | -977 | -980 | -960 |
| 442 | 427 | 419 | 389 | 362 | 330 | 299 |
| (168) | (237) | (326) | (524) | (615) | (650) | (661) |
| 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 3,785 | 3,504 | 3,244 | 3,003 | 2,780 | 2,574 | 2,383 |
| 5,985 | 5,392 | 4,855 | 4,474 | 4,230 | 3,948 | 3,780 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 1,580 | 1,343 | 1,128 | 1,041 | 1,075 | 1,053 | 1,132 |
| 620 | 545 | 483 | 429 | 375 | 321 | 265 |
| 11,408 | 10,065 | 8,937 | 7,895 | 6,821 | 5,768 | 4,636 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| -1,580 | -1,343 | -1,128 | -1,041 | -1,075 | -1,053 | -1,132 |
| -695 | -591 | -496 | -458 | -473 | -463 | -498 |

| 2038-39 | 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 |
|---|---|---|---|---|---|---|
| -669 | -567 | -487 | -462 | -470 | -472 | -505 |
| -930 | -801 | -695 | -646 | -629 | -608 | -615 |
| 261 | 234 | 208 | 184 | 159 | 137 | 110 |
| (669) | (567) | (487) | (462) | (470) | (472) | (505) |
| 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% | 4.4% |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 2,206 | 2,042 | 1,891 | 1,750 |
| 3,611 | 3,608 | 3,952 | 1,750 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 1,199 | 1,427 | 2,010 | 0 |
| 206 | 139 | 51 | 0 |
| 3,437 | 2,010 | 0 | 0 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| -1,199 | -1,427 | -2,010 | 0 |
| -528 | -628 | -885 | 0 |

| 2045-46 | 2046-47 | 2047-48 |
|---|---|---|
| -553 | -692 | -663 |
| -637 | -748 | -675 |
| 85 | 56 | 11 |
| | | |
| (553) | (692) | (663) |
| | | |
| 4.4% | 4.4% | 4.4% |

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayme**

| *$ millions* | **2017** | **2018** |
|---|---|---|
| IESO forecast Global A | 10,078 | 10,144 |
| Global Adjustment pay | 8,682 | 7,955 |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for a
** Represents total OFHP costs recovered from consumers, including deferral

| | | |
|---|---|---|
| Deferral | 1,396 | 2,189 |
| | 52 | 133 |
| Annual Borrowings | 1,448 | 2,322 |
| TOTAL | 1,448 | 3,770 |
| | | |
| | 0.03719145 | 0.060789592 |
| | 0.035857845 | 0.035294613 |
| | 0.03719145 | 0.036585899 |
| | 0.0358578446 | 0.0510000000 |
| | 0.0371914498 | 0.0537407798 |
| | 0.0371914498 | 0.0523345305 |
| | | |
| | 5% | |
| | | |
| Recalculation | 1,396 | 2,189 |
| | 52 | 130 |
| | 1,448 | 2,319 |
| | 1,448 | 3,768 |

**nt Amount Cash Flows**

| 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|
| 10,801 | 10,576 | 9,671 | 9,471 |
| 8,505 | 8,162 | 7,467 | 7,771 |

ll customers (2017-2035) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by
of GA and recovery of principal, interest and fees.

| | | | |
|---|---|---|---|
| 2,296 | 2,414 | 2,204 | 1,700 |
| 257 | 394 | 536 | 663 |
| 2,553 | 2,808 | 2,740 | 2,363 |
| 6,323 | 9,131 | 11,871 | 14,234 |
| | | | |
| 0.112122144 | 0.163279846 | 0.242946991 | 0.390032973 |
| 0.040704571 | 0.043159126 | 0.045114332 | 0.046583166 |
| 0.042431736 | 0.045105856 | 0.047245794 | 0.048859181 |
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0508000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0535187526 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0521239483 |
| | 0.050837963 | | |
| | | | |
| 2,296 | 2,414 | 2,204 | 1,700 |
| 252 | 386 | 524 | 651 |
| 2,548 | 2,799 | 2,728 | 2,351 |
| 6,315 | 9,115 | 11,843 | 14,194 |

| 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|
| 8,733 | 9,917 | 8,924 | 9,908 |
| 7,683 | 9,425 | 8,924 | 9,908 |

y assuming 2% CPI and extrapolated post-2035 based on the average rate of change between 2026-2035.

| | | | |
|---|---|---|---|
| 1,050 | 492 | 0 | 0 |
| 769 | 850 | 907 | 954 |
| 1,819 | 1,342 | 907 | 954 |
| 16,053 | 17,395 | 18,301 | 19,255 |
| | | | |
| 0.73265484 | 1.72677531 | #DIV/0! | #DIV/0! |
| 0.047921434 | 0.048841011 | 0.049541642 | 0.049541642 |
| 0.050333487 | 0.051348946 | 0.052123948 | 0.052123948 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 1,050 | 492 | 0 | 0 |
| 755 | 833 | 888 | 934 |
| 1,805 | 1,325 | 888 | 934 |
| 15,999 | 17,324 | 18,212 | 19,146 |

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| 10,169 | 10,300 | 9,978 | 9,472 |
| 10,169 | 11,297 | 11,009 | 10,877 |

| | | | |
|---|---|---|---|
| 0 | -997 | -1,031 | -1,406 |
| 1,004 | 1,030 | 1,031 | 1,021 |
| 1,004 | 33 | 0 | -385 |
| 20,259 | 20,292 | 20,292 | 19,907 |
| | | | |
| #DIV/0! | -1.033303874 | -1 | -0.726329513 |
| | | | |
| 0.052123948 | 0.053472634 | 0.053518753 | 0.054063854 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 0 | -997 | -1,031 | -1,406 |
| 982 | 1007 | 1006 | 995 |
| 982 | 10 | -25 | -410 |
| 20,128 | 20,138 | 20,113 | 19,703 |

| 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 |
| 9,789 | 9,840 | 9,009 | 8,291 |

| | | | |
|---|---|---|---|
| -1,340 | -1,496 | -1,564 | -2,039 |
| 1,003 | 981 | 952 | 908 |
| -337 | -515 | -611 | -1,131 |
| 19,570 | 19,055 | 18,444 | 17,313 |
| | | | |
| -0.748423197 | -0.655724615 | -0.609140601 | |
| | | | |
| 0.054004521 | 0.054281378 | 0.054453742 | 0.055363212 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| -1,340 | -1,496 | -1,564 | -2,039 |
| 976 | 953 | 924 | 879 |
| -364 | -543 | -640 | -1,160 |
| 19,339 | 18,796 | 18,156 | 16,996 |

| 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|
| 4,771 | 4,417 | 4,089 | 3,785 |
| 6,988 | 6,666 | 6,262 | 5,985 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 845 | 772 | 697 | 620 |
| -1,372 | -1,477 | -1,476 | -1,580 |
| 15,941 | 14,464 | 12,988 | 11,408 |

| | | | |
|---|---|---|---|
| 0.055951526 | | | |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 815 | 742 | 667 | 589 |
| -1,402 | -1,507 | -1,507 | -1,611 |
| 15,594 | 14,087 | 12,580 | 10,968 |

| 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|
| 3,504 | 3,244 | 3,003 | 2,780 |
| 5,392 | 4,855 | 4,474 | 4,230 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 545 | 483 | 429 | 375 |
| -1,343 | -1,128 | -1,041 | -1,075 |
| 10,065 | 8,937 | 7,895 | 6,821 |

| | | | |
|---|---|---|---|
| 0.0508000000 | 0.0508000000 | 0.0510000000 | 0.0510000000 |
| 0.0535187526 | 0.0535187526 | 0.0537407798 | 0.0537407798 |
| 0.0521239483 | 0.0521239483 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 514 | 451 | 395 | 340 |
| -1,374 | -1,160 | -1,076 | -1,110 |
| 9,595 | 8,434 | 7,358 | 6,249 |

| 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|
| 2,574 | 2,383 | 2,206 | 2,042 |
| 3,948 | 3,780 | 3,611 | 3,608 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 321 | 265 | 206 | 139 |
| -1,053 | -1,132 | -1,199 | -1,427 |
| 5,768 | 4,636 | 3,437 | 2,010 |

| | | | |
|---|---|---|---|
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0510000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0537407798 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 285 | 229 | 169 | 101 |
| -1,088 | -1,168 | -1,236 | -1,464 |
| 5,160 | 3,992 | 2,756 | 1,291 |

| 2047 | 2048 |
|---|---|
| 1,891 | 1,750 |
| 3,952 | 1,750 |

| | |
|---|---|
| -2,062 | 0 |
| 51 | 0 |
| -2,010 | 0 |
| 0 | 0 |

| | |
|---|---|
| 0.0510000000 | 0.0000000000 |
| 0.0537407798 | 0.0000000000 |
| 0.0523345305 | 0.0000000000 |

| | |
|---|---|
| -2,062 | 0 |
| 13 | -39 |
| -2,048 | -39 |
| -757 | -796 |

***NOTE:*** *Draft version for Comment. Inputs and assumptions may not be consistent with best information available.*

## Attempted Recreation of Energy's Octo

**INPUTS:**

| Calculation for Scenario Analysis | | |
|---|---|---|
| Provincial Borrowing | 4.50% | *<-- Change this number to test differ* |
| Basis Points | 50 bp | *<-- Number used for scenario analys* |
| Total (Interest Rate) | 5.0000% | |
| **Model Circularity** | ON | |

**OUTPUTS:**

| Interest Calculation | | |
|---|---|---|
| **Interest Rate:** | 5.00% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 21,083 | *NOTE: Calculations do not match En* |

**SENSITIVITIES:** *Determine sensitivites at various rates*

| | | Total Interest Paid |
|---|---|---|
| Provincial Borrowing | Provincial Borrowing + | Provincial Borrowing + |
| 21,083 | 0 bp | 30 bp |
| 3.12% | 21,083 | 21,083 |
| 3.50% | 21,083 | 21,083 |
| 3.75% | 21,083 | 21,083 |
| 4.00% | 21,083 | 21,083 |
| 4.25% | 21,083 | 21,083 |
| 4.50% | 21,083 | 21,083 |

*Sensitivites and difference compared to provincial borrowing*

| | Difference in Interest Paid Compared to Provin | |
|---|---|---|
| | Provincial Borrowing + 0 bp | Provincial Borrowing + 30 bp |
| 3.12% | - | - |
| 3.50% | - | - |
| 3.75% | - | - |
| 4.00% | - | - |
| 4.25% | - | - |
| 4.50% | - | - |

**ISSUANCE ANALYSIS:**

| | | Weighted Average Borrowing Calcul |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |
| | | **WEIGHTED AVERAGE:** |

| | | |
|---|---|---|
| FHT Weighted Average Rate: | 3.526% | |
| FHT Interest Paid | 10,399 | |
| | | |
| Provincial Borrowing at Issuance: | 3.12% | *Source: OFA* |
| Provincial Interest Paid | 8,540 | |
| | | |
| **Difference in Interest:** | **1,858** | |

## ɔber 19 Analysis by EFB

*ɾent interest rates*
*ɨis*

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinement.*

| | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| 21,083 | 21,083 |
| 21,083 | 21,083 |
| 21,083 | 21,083 |
| 21,083 | 21,083 |
| 21,083 | 21,083 |
| 21,083 | 21,083 |

| cial Borrowing: | |
|---|---|
| Provincial Borrowing + 40 bp | Provincial Borrowing + 50 bp |
| - | - |
| - | - |
| - | - |
| - | - |
| - | - |
| - | - |

| ation | |
|---|---|
| 3.357% | *Source: Debt Issuance* |
| 3.64% | *Source: Email* |
| 3.96% | *Source: Email* |
| **3.526%** | |

**INPUTS:**

| Calculation for Scenario Analysis | |
|---|---|
| Provincial Borrowing | 4.50% |
| Basis Points | 00 bp |
| Total (Interest Rate) | 4.50% |

**OUTPUTS:**

| Interest Calculation | |
|---|---|
| **Interest Rate:** | 4.50% |
| **Year Interest Payments Stop:** | 2047 |
| **Total Interest Paid:** | 14,308 |
| **Peak Debt:** | 17,612 |
| **Annual Paydown Amount:** | (1,278) |

**SCENARIOS:**

| | 3.12% | |
|---|---|---|
| **Interest Rate:** | 3.12% | |
| **Year Interest Payments Stop:** | 2047 | |
| **Total Interest Paid:** | 9,038 | |
| **Peak Debt:** | 16,348 | |
| **Annual Paydown Amount:** | (1,038) | |
| **Difference in Interest Paid:** | | 1,4 |

## Scenario Analysis with EFB Model

| 3.12% + 40bp | 4.50% | 4.5% + 50bp |
|---|---|---|
| 3.52% | 4.50% | 5.00% |
| 2047 | 2047 | 2047 |
| 10,477 | 14,308 | 16,438 |
| 16,705 | 17,612 | 18,093 |
| (1,104) | (1,278) | (1,375) |
| 39 | 2,130 | |

OFHP debt and interest projections, by calendar year

| $ nominal million | 2017 |
|---|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* | (1,396) |
| Interest Paid | 32 |
| Closing Debt Balance | 1,428 |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

## Attempted recreation by EFB ($ nominal Million)

Interest:
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**

| | **2017** |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** ***(Exactly from above)*** | 1,396 |
| Interest Paid (attempted recreation) [EFB Calculation] | 36 |
| Closing Debt Balance [EFB Calculation] | 1,432 |

***3.66***

## Attempted recreation and extrapolation by EFB ($ nominal Million)

**Interest:**
**Year Interest Payments Stop:**
**Total Interest Paid - Positive:**
**Peak Debt:**

| | **2017** |
|---|---|

| | |
|---|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** | |
| ***(Exactly from above)*** | 1,396 |
| *Reduction* | |
| **Opening Debt:** | 0 |
| **IN YEAR ANALYSIS** | |
| **In-Year Interest:** | 29 |
| **In-Year Accumulated Debt (Excl Interest):** | 1,396 |
| **In-Year - End Debt:** | 1,425 |
| **Debt Interest from Prior Year:** | 0 |
| **Total Accumulated Interest:** | 29 |
| **Accumulated Debt:** | 1,396 |
| **Debt Reduction:** | |
| **Closing Debt:** | 1,425 |

| | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|
| | (2,189) | (2,296) | (2,414) | (2,204) | (1,700) |
| | 116 | 225 | 343 | 466 | 577 |
| | 3,734 | 6,254 | 9,011 | 11,681 | 13,958 |

5.00%
**2047**
**21,083**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|
| | 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| | | | | | Additional Borrowing/F |
| | 130 | 251 | 385 | 523 | 650 |
| | 3,751 | 6,297 | 9,096 | 11,823 | 14,173 |
| | ***17.09*** | ***43.57*** | ***84.95*** | ***142.36*** | ***215.40*** |

4.50%
**2047**
**14,308**
**17,612**

| | **2018** | **2019** | **2020** | **2021** | **2022** |
|---|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 1,425 | 3,724 | 6,235 | 8,980 | 11,634 |
| 46 | 48 | 50 | 46 | 36 |
| 2,189 | 2,296 | 2,414 | 2,204 | 1,700 |
| 2,235 | 2,344 | 2,464 | 2,250 | 1,736 |
| 64 | 168 | 281 | 404 | 524 |
| 110 | 216 | 331 | 450 | 559 |
| 3,614 | 6,020 | 8,649 | 11,184 | 13,334 |
| 3,724 | 6,235 | 8,980 | 11,634 | 13,894 |

| 2023 | 2024 | 2025 | 2026 | 2027 |
|---|---|---|---|---|
| (1,050) | (492) | (61) | 79 | 129 |
| 667 | 733 | 778 | 814 | 851 |
| 15,674 | 16,899 | 17,677 | 18,491 | 19,342 |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|
| 1,050 | 492 | 61 | (79) | (129) |
| | | Cross Over Point: | (61) | |
| | | Borrrowing Still Required: | 79 | 129 |
| Repayments [Reason Unknown, Plug]: | | | | |
| 754 | 832 | 887 | 933 | 981 |
| 15,977 | 17,301 | 18,188 | 19,121 | 20,101 |
| ***302.42*** | ***401.45*** | ***510.70*** | ***629.63*** | ***758.92*** |

| **2023** | **2024** | **2025** | **2026** | **2027** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| 1,050 | 492 | 61 | | |
| | | | -1278 | -1278 |
| 13,894 | 15,591 | 16,794 | 17,612 | 17,127 |
| | | | | |
| 22 | 10 | 1 | 0 | 0 |
| 1,050 | 492 | 61 | 0 | 0 |
| 1,072 | 502 | 62 | 0 | 0 |
| | | | | |
| 625 | 702 | 756 | 793 | 771 |
| | | | | |
| 647 | 712 | 757 | 793 | 771 |
| 14,944 | 16,083 | 16,855 | 17,612 | 17,127 |
| | | | (1,278) | (1,278) |
| | | | | |
| 15,591 | 16,794 | 17,612 | 17,127 | 16,620 |

| 2028 | 2029 | 2030 | 2031 | 2032 |
|---|---|---|---|---|
| 354 | 714 | 1,251 | 1,188 | 1,348 |
| 883 | 896 | 888 | 872 | 854 |
| 19,904 | 19,904 | 19,541 | 19,226 | 18,732 |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|
| (354) | (714) | (1,251) | (1,188) | (1,348) |
| 33.45 | (182) | | | |
| 1,023 | 1,044 | 1,042 | 1,033 | 1,021 |
| 20,803 | 20,951 | 20,743 | 20,588 | 20,262 |
| ***898.48*** | ***1046.63*** | ***1201.44*** | ***1362.46*** | ***1529.65*** |

| **2028** | **2029** | **2030** | **2031** | **2032** |
|---|---|---|---|---|

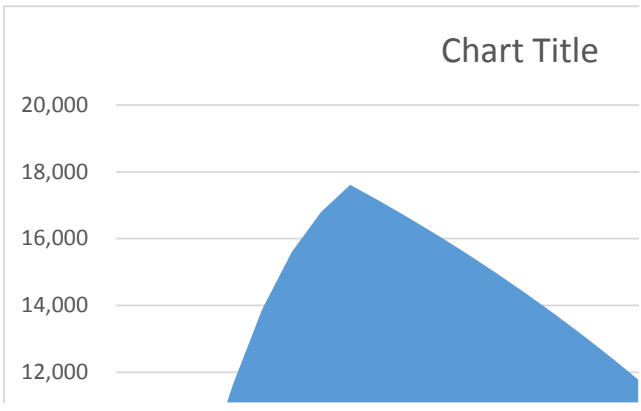
| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 748 | 724 | 699 | 673 | 646 |
| 748 | 724 | 699 | 673 | 646 |
| 16,620 | 16,090 | 15,537 | 14,958 | 14,354 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 16,090 | 15,537 | 14,958 | 14,354 | 13,722 |

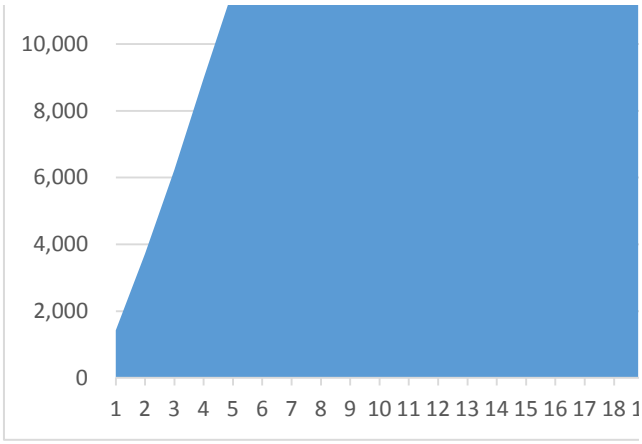
| 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|
| 1,419 | 1,901 | 2,087 | 2,128 | 2,062 |
| 830 | 791 | 736 | 673 | 607 |
| 18,143 | 17,033 | 15,682 | 14,227 | 12,773 |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|
| (1,419) | (1,901) | (2,087) | (2,128) | (2,062) |
| 1,003 | 969 | 916 | 855 | 792 |
| 19,845 | 18,913 | 17,743 | 16,470 | 15,200 |
| ***1702.65*** | ***1880.16*** | ***2060.46*** | ***2242.82*** | ***2427.07*** |

| **2033** | **2034** | **2035** | **2036** | **2037** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 617 | 588 | 557 | 524 | 490 |
| 617 | 588 | 557 | 524 | 490 |
| 13,722 | 13,062 | 12,372 | 11,651 | 10,897 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 13,062 | 12,372 | 11,651 | 10,897 | 10,110 |




10,000
8,000
6,000
4,000
2,000
0
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 1

| 2038 | 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|---|
| 2,099 | 1,796 | 1,527 | 1,392 | 1,379 |
| 540 | 475 | 420 | 372 | 326 |
| 11,214 | 9,893 | 8,786 | 7,766 | 6,713 |

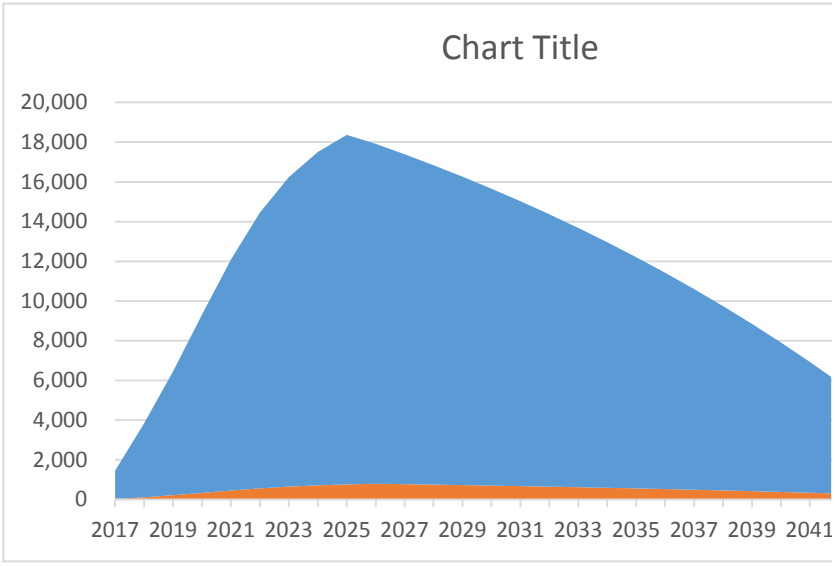


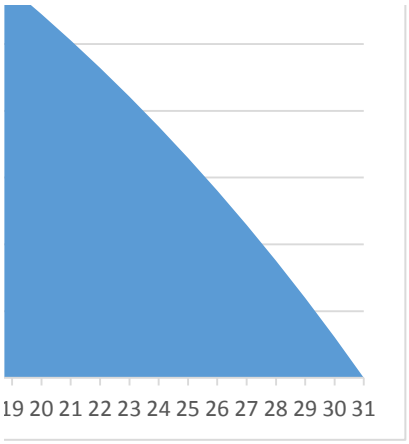
| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|
| (2,099) | (1,796) | (1,527) | (1,392) | (1,379) |
| 726 | 663 | 612 | 568 | 526 |
| 13,827 | 12,694 | 11,779 | 10,955 | 10,102 |
| ***2613.03*** | ***2801.15*** | ***2992.70*** | ***3188.61*** | ***3389.25*** |



| **2038** | **2039** | **2040** | **2041** | **2042** |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 |
| 455 | 418 | 379 | 339 | 297 |
| 455 | 418 | 379 | 339 | 297 |
| 10,110 | 9,287 | 8,427 | 7,529 | 6,590 |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 9,287 | 8,427 | 7,529 | 6,590 | 5,609 |




19 20 21 22 23 24 25 26 27 28 29 30 31

| 2043 | 2044 | 2045 | 2046 | 2047 |
|---|---|---|---|---|
| 1,310 | 1,341 | 1,357 | 1,526 | 2,034 |
| 279 | 231 | 179 | 121 | 45 |
| 5,682 | 4,571 | 3,394 | 1,989 | 0 |

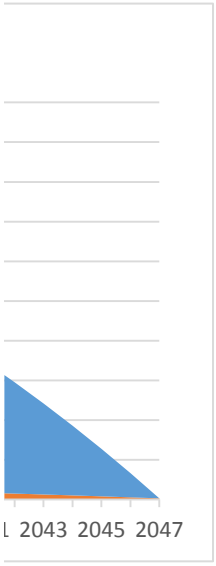


| **2043** | **2044** | **2045** | **2046** | **2047** |
|---|---|---|---|---|
| (1,310) | (1,341) | (1,357) | (1,526) | (2,034) |
| 484 | 441 | 395 | 341 | 267 |
| 9,277 | 8,377 | 7,415 | 6,230 | 4,464 |
| ***3594.84*** | ***3805.48*** | ***4021.06*** | ***4241.07*** | ***4463.66*** |



| **2043** | **2044** | **2045** | **2046** | **2047** | **2048** | **2049** |
|---|---|---|---|---|---|---|

| | | | | | | |
|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 252 | 206 | 158 | 108 | 55 | 0 | (57) |
| 5,609 | 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| 4,584 | 3,512 | 2,393 | 1,223 | 0 | (1,278) | (2,613) |



| 2050 | 2051 | 2052 | 2053 | 2054 | 2055 | 2056 | 2057 | 2058 |
|---|---|---|---|---|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 | -1278 |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (118) | (180) | (246) | (315) | (386) | (461) | (539) | (621) | (707) |
| (2,613) | (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) |
| (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) | (1,278) |
| (4,008) | (5,466) | (6,990) | (8,582) | (10,246) | (11,985) | (13,802) | (15,700) | (17,685) |

| 2059 | 2060 | 2061 | 2062 | 2063 | 2064 | 2065 |
|---|---|---|---|---|---|---|

| | |
|---|---|
| -1278 | -1278 |
| | |
| (17,685) | (19,758) |
| | |
| | |
| 0 | 0 |
| 0 | 0 |
| 0 | 0 |
| | |
| (796) | (889) |
| | |
| (796) | (889) |
| (17,685) | (19,758) |
| (1,278) | (1,278) |
| | |
| (19,758) | (21,925) |

**Instructions: An updated projection of the annual cost of the refinancing portion of the Fa**

**Please contact Matt Gurham (mgurham@fao-on.org) if assistance is required.**

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayment Amount Cash Flows**

| *$ millions* |
|---|
| IESO forecast Global Adjustment cost * |
| Global Adjustment payment from ratepayer ** |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for all customers (2017-203
** Represents total OFHP costs recovered from consumers, including deferral of GA and recovery of

**Provincial Actual and Projected Fair Hydro Plan Debt**

| *$ millions* |
|---|
| Amount borrowed/paid-back in given year*** |
| Interest**** ~~on accumulated debt from previous year~~ |
| Accumulated Debt |

***Values represent deferral of GA costs and recovery of principal.
****Interest is calculated based on the average debt balance for the year and a 5 per cent interest ra
This data was used to inform the Minister's letter to OPG.

**OPG Actual and Projected Fair Hydro Plan Debt**

| *$ million* |
|---|
| Amount borrowed/paid-back in given year |
| Interest on accumulated debt from previous year |
| Accumulated Debt |

## Equity Injection Comparisons

Revised Annual Borrowings
Equity Injection (44%)

Revised Equity Injections - Fiscalized
EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)
Variance

## IOD Comparisons

***Revised Equity Injections - Fiscalized***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

***EFB Equity Injection Calculation based on FAA (September 28 2017 Letter)***
OEP forecast as of Feb 6, 2018
Interest Rate Forecast

IOD
2017-18
2018-19
2019-20
2020-21
**Total Estimated IOD Impact**

**Variance in IOD Impacts**

**ıir Hydro Plan.**

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 10,078 | 10,144 | 10,801 | 10,576 | 9,671 | 9,471 | 8,733 |
| 8,682 | 7,955 | 8,505 | 8,162 | 7,467 | 7,771 | 7,683 |

:5) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by assuming 2% CPI
principal, interest and fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| -1,448 | -2,322 | -2,553 | -2,808 | -2,740 | -2,363 | -1,819 |
| 52 | 133 | 257 | 394 | 536 | 663 | 769 |
| 1,448 | 3,770 | 6,323 | 9,131 | 11,871 | 14,234 | 16,053 |

ate over the 30-year life of the program, and includes associated fees.

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|---|---|
| 1,448 | 2,322 | 2,553 | 2,808 | 2,740 | 2,363 | 1,819 |
| 637 | 1022 | 1123 | 1235 | 1206 | 1040 | 800 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 | 2022-23 | 2023-24 |
|---|---|---|---|---|---|---|
| 893 | 1047 | 1151 | 1228 | 1164 | 980 | 748 |
| 853 | 979 | 1023 | 1035 | 911 | 675 | 402 |
| 40 | 69 | 128 | 193 | 253 | 305 | 346 |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|
| 893 | 1,047 | 1,151 | 1,228 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 11 | 21 | 21 | 21 |
| | 18 | 35 | 35 |
| | | 23 | 46 |
| | | | 27 |
| **11** | **39** | **80** | **130** |
| | | | |
| 853 | 979 | 1,023 | 1,035 |
| rrowing Rate | OEP | OEP | 20-Year Average |
| 2.4% | 3.4% | 4.0% | 4.4% |
| | | | |
| 10 | 20 | 20 | 20 |
| | 16 | 33 | 33 |
| | | 21 | 41 |
| | | | 23 |
| **10** | **37** | **74** | **117** |
| | | | |
| **0** | **2** | **6** | **13** |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 9,917 | 8,924 | 9,908 | 10,169 | 10,300 | 9,978 | 9,472 |
| 9,425 | 8,924 | 9,908 | 10,169 | 11,297 | 11,009 | 10,877 |

and extrapolated post-2035 based on the average rate of change between 2026-2035.

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| -1,342 | -907 | -954 | -1,004 | -33 | 0 | 385 |
| 850 | 907 | 954 | 1,004 | 1,030 | 1,031 | 1,021 |
| 17,395 | 18,301 | 19,255 | 20,259 | 20,292 | 20,292 | 19,907 |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|
| 1,342 | 907 | 954 | 1,004 | 33 | 0 | -385 |
| 590 | 399 | 420 | 442 | 15 | 0 | -169 |

| 2024-25 | 2025-26 | 2026-27 | 2027-28 | 2028-29 | 2029-30 | 2030-31 |
|---|---|---|---|---|---|---|
| 542 | 404 | 425 | 335 | 11 | -42 | -164 |
| 152 | -51 | -112 | -159 | -270 | -444 | -604 |
| 390 | 455 | 537 | 494 | 281 | 402 | 440 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 | 4,771 | 4,417 | 4,089 |
| 9,789 | 9,840 | 9,009 | 8,291 | 6,988 | 6,666 | 6,262 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| 337 | 515 | 611 | 1,131 | 1,372 | 1,477 | 1,476 |
| 1,003 | 981 | 952 | 908 | 845 | 772 | 697 |
| 19,570 | 19,055 | 18,444 | 17,313 | 15,941 | 14,464 | 12,988 |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2031 | 2032 | 2033 | 2034 | 2035 | 2036 | 2037 |
|---|---|---|---|---|---|---|
| -337 | -515 | -611 | -1,131 | -1,372 | -1,477 | -1,476 |
| -148 | -227 | -269 | -498 | -604 | -650 | -650 |

| 2031-32 | 2032-33 | 2033-34 | 2034-35 | 2035-36 | 2036-37 | 2037-38 |
|---|---|---|---|---|---|---|
| -168 | -237 | -326 | -524 | -615 | -650 | -661 |
| -609 | -664 | -745 | -913 | -977 | -980 | -960 |
| 442 | 427 | 419 | 389 | 362 | 330 | 299 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 3,785 | 3,504 | 3,244 | 3,003 | 2,780 | 2,574 | 2,383 |
| 5,985 | 5,392 | 4,855 | 4,474 | 4,230 | 3,948 | 3,780 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| 1,580 | 1,343 | 1,128 | 1,041 | 1,075 | 1,053 | 1,132 |
| 620 | 545 | 483 | 429 | 375 | 321 | 265 |
| 11,408 | 10,065 | 8,937 | 7,895 | 6,821 | 5,768 | 4,636 |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| | | | | | | |
| | | | | | | |
| | | | | | | |
| | | | | | | |

| 2038 | 2039 | 2040 | 2041 | 2042 | 2043 | 2044 |
|---|---|---|---|---|---|---|
| -1,580 | -1,343 | -1,128 | -1,041 | -1,075 | -1,053 | -1,132 |
| -695 | -591 | -496 | -458 | -473 | -463 | -498 |

| 2038-39 | 2039-40 | 2040-41 | 2041-42 | 2042-43 | 2043-44 | 2044-45 |
|---|---|---|---|---|---|---|
| -669 | -567 | -487 | -462 | -470 | -472 | -505 |
| -930 | -801 | -695 | -646 | -629 | -608 | -615 |
| 261 | 234 | 208 | 184 | 159 | 137 | 110 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 2,206 | 2,042 | 1,891 | 1,750 |
| 3,611 | 3,608 | 3,952 | 1,750 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| 1,199 | 1,427 | 2,010 | 0 |
| 206 | 139 | 51 | 0 |
| 3,437 | 2,010 | 0 | 0 |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| | | | |
| | | | |
| | | | |
| | | | |

| 2045 | 2046 | 2047 | 2048 |
|---|---|---|---|
| -1,199 | -1,427 | -2,010 | 0 |
| -528 | -628 | -885 | 0 |

| 2045-46 | 2046-47 | 2047-48 |
|---|---|---|
| -553 | -692 | -663 |
| -637 | -748 | -675 |
| 85 | 56 | 11 |

Switch 1

**Actual and Projected Annual Global Adjustment (GA) Deferral and Repayme**

| *$ millions* | **2017** | **2018** |
|---|---|---|
| IESO forecast Global A | 10,078 | 10,144 |
| Global Adjustment pay | 8,682 | 7,955 |

* Represents total GA prior to OFHP based on IESO's forecast of total GA for a
** Represents total OFHP costs recovered from consumers, including deferral

| | | |
|---|---|---|
| Deferral | 1,396 | 2,189 |
| | 52 | 133 |
| Annual Borrowings | 1,448 | 2,322 |
| TOTAL | 1,448 | 3,770 |
| | 0.03719145 | 0.060789592 |
| | 0.035857845 | 0.035294613 |
| | 0.03719145 | 0.036585899 |
| | 0.0358578446 | 0.0510000000 |
| | 0.0371914498 | 0.0537407798 |
| | 0.0371914498 | 0.0523345305 |
| | 5% | |
| Recalculation | 1,396 | 2,189 |
| | 52 | 130 |
| | 1,448 | 2,319 |
| | 1,448 | 3,768 |

**nt Amount Cash Flows**

| 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|
| 10,801 | 10,576 | 9,671 | 9,471 |
| 8,505 | 8,162 | 7,467 | 7,771 |

ll customers (2017-2035) which informed the 2017 LTEP, converted by the Ministry from $2017 to $nominal by
of GA and recovery of principal, interest and fees.

| | | | |
|---|---|---|---|
| 2,296 | 2,414 | 2,204 | 1,700 |
| 257 | 394 | 536 | 663 |
| 2,553 | 2,808 | 2,740 | 2,363 |
| 6,323 | 9,131 | 11,871 | 14,234 |
| | | | |
| 0.112122144 | 0.163279846 | 0.242946991 | 0.390032973 |
| 0.040704571 | 0.043159126 | 0.045114332 | 0.046583166 |
| 0.042431736 | 0.045105856 | 0.047245794 | 0.048859181 |
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0508000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0535187526 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0521239483 |
| | 0.050837963 | | |
| | | | |
| 2,296 | 2,414 | 2,204 | 1,700 |
| 252 | 386 | 524 | 651 |
| 2,548 | 2,799 | 2,728 | 2,351 |
| 6,315 | 9,115 | 11,843 | 14,194 |

| 2023 | 2024 | 2025 | 2026 |
|---|---|---|---|
| 8,733 | 9,917 | 8,924 | 9,908 |
| 7,683 | 9,425 | 8,924 | 9,908 |

y assuming 2% CPI and extrapolated post-2035 based on the average rate of change between 2026-2035.

| | | | |
|---|---|---|---|
| 1,050 | 492 | 0 | 0 |
| 769 | 850 | 907 | 954 |
| 1,819 | 1,342 | 907 | 954 |
| 16,053 | 17,395 | 18,301 | 19,255 |
| | | | |
| 0.73265484 | 1.72677531 | #DIV/0! | #DIV/0! |
| 0.047921434 | 0.048841011 | 0.049541642 | 0.049541642 |
| 0.050333487 | 0.051348946 | 0.052123948 | 0.052123948 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 1,050 | 492 | 0 | 0 |
| 755 | 833 | 888 | 934 |
| 1,805 | 1,325 | 888 | 934 |
| 15,999 | 17,324 | 18,212 | 19,146 |

| 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|
| 10,169 | 10,300 | 9,978 | 9,472 |
| 10,169 | 11,297 | 11,009 | 10,877 |

| | | | |
|---|---|---|---|
| 0 | -997 | -1,031 | -1,406 |
| 1,004 | 1,030 | 1,031 | 1,021 |
| 1,004 | 33 | 0 | -385 |
| 20,259 | 20,292 | 20,292 | 19,907 |
| | | | |
| #DIV/0! | -1.033303874 | -1 | -0.726329513 |
| | | | |
| 0.052123948 | 0.053472634 | 0.053518753 | 0.054063854 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| 0 | -997 | -1,031 | -1,406 |
| 982 | 1007 | 1006 | 995 |
| 982 | 10 | -25 | -410 |
| 20,128 | 20,138 | 20,113 | 19,703 |

| 2031 | 2032 | 2033 | 2034 |
|---|---|---|---|
| 8,449 | 8,344 | 7,445 | 6,252 |
| 9,789 | 9,840 | 9,009 | 8,291 |

| | | | |
|---|---|---|---|
| -1,340 | -1,496 | -1,564 | -2,039 |
| 1,003 | 981 | 952 | 908 |
| -337 | -515 | -611 | -1,131 |
| 19,570 | 19,055 | 18,444 | 17,313 |
| | | | |
| -0.748423197 | -0.655724615 | -0.609140601 | |
| | | | |
| 0.054004521 | 0.054281378 | 0.054453742 | 0.055363212 |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |
| | | | |
| -1,340 | -1,496 | -1,564 | -2,039 |
| 976 | 953 | 924 | 879 |
| -364 | -543 | -640 | -1,160 |
| 19,339 | 18,796 | 18,156 | 16,996 |

| 2035 | 2036 | 2037 | 2038 |
|---|---|---|---|
| 4,771 | 4,417 | 4,089 | 3,785 |
| 6,988 | 6,666 | 6,262 | 5,985 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 845 | 772 | 697 | 620 |
| -1,372 | -1,477 | -1,476 | -1,580 |
| 15,941 | 14,464 | 12,988 | 11,408 |

| | | | |
|---|---|---|---|
| 0.055951526 | | | |
| 0.0508000000 | 0.0508000000 | 0.0508000000 | 0.0508000000 |
| 0.0535187526 | 0.0535187526 | 0.0535187526 | 0.0535187526 |
| 0.0521239483 | 0.0521239483 | 0.0521239483 | 0.0521239483 |

| | | | |
|---|---|---|---|
| -2,217 | -2,249 | -2,173 | -2,200 |
| 815 | 742 | 667 | 589 |
| -1,402 | -1,507 | -1,507 | -1,611 |
| 15,594 | 14,087 | 12,580 | 10,968 |

| 2039 | 2040 | 2041 | 2042 |
|---|---|---|---|
| 3,504 | 3,244 | 3,003 | 2,780 |
| 5,392 | 4,855 | 4,474 | 4,230 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 545 | 483 | 429 | 375 |
| -1,343 | -1,128 | -1,041 | -1,075 |
| 10,065 | 8,937 | 7,895 | 6,821 |

| | | | |
|---|---|---|---|
| 0.0508000000 | 0.0508000000 | 0.0510000000 | 0.0510000000 |
| 0.0535187526 | 0.0535187526 | 0.0537407798 | 0.0537407798 |
| 0.0521239483 | 0.0521239483 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,888 | -1,611 | -1,471 | -1,450 |
| 514 | 451 | 395 | 340 |
| -1,374 | -1,160 | -1,076 | -1,110 |
| 9,595 | 8,434 | 7,358 | 6,249 |

| 2043 | 2044 | 2045 | 2046 |
|---|---|---|---|
| 2,574 | 2,383 | 2,206 | 2,042 |
| 3,948 | 3,780 | 3,611 | 3,608 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 321 | 265 | 206 | 139 |
| -1,053 | -1,132 | -1,199 | -1,427 |
| 5,768 | 4,636 | 3,437 | 2,010 |

| | | | |
|---|---|---|---|
| 0.0510000000 | 0.0510000000 | 0.0510000000 | 0.0510000000 |
| 0.0537407798 | 0.0537407798 | 0.0537407798 | 0.0537407798 |
| 0.0523345305 | 0.0523345305 | 0.0523345305 | 0.0523345305 |

| | | | |
|---|---|---|---|
| -1,374 | -1,397 | -1,405 | -1,565 |
| 285 | 229 | 169 | 101 |
| -1,088 | -1,168 | -1,236 | -1,464 |
| 5,160 | 3,992 | 2,756 | 1,291 |

| 2047 | 2048 |
|---|---|
| 1,891 | 1,750 |
| 3,952 | 1,750 |

| | |
|---|---|
| -2,062 | 0 |
| 51 | 0 |
| -2,010 | 0 |
| 0 | 0 |

| | |
|---|---|
| 0.0510000000 | 0.0000000000 |
| 0.0537407798 | 0.0000000000 |
| 0.0523345305 | 0.0000000000 |

| | |
|---|---|
| -2,062 | 0 |
| 13 | -39 |
| -2,048 | -39 |
| -757 | -796 |

| Interest Calculation | |
|---|---|
| **Interest Rate:** | 3.1200% |
| **Year Interest Payments Stop:** | 2043 |
| **Total Interest Paid - Positive:** | 8,540 |
| **Net Interest Paid to 2047** | 7,887 |

*NOTE: Calculations do not match En*

| | | **Weighted Average Borrowi** |
|---|---|---|
| Tranche A - Senior Debt | 51% | FHT: |
| Tranche B - Sub Debt | 39% | OPG via Province |
| Tranche C - Jr. Sub Debt | 10% | OPG via Province & Cap Mkts |
| | | **WEIGHTED AVERAGE:** |

| | **Interest Rate** | **Total Interest Paid - Positive** |
|---|---|---|
| Original Borrowing Rates: | 4.50% | 16,589 |
| FHT Borrowing: | 3.357% | 9,584 |
| Provincial Borrowing: | 3.12% | 8,540 |
| Weighted Avg Borrowing: | 4.017% | 13,138 |

| **Difference In Interest Charges** | |
|---|---|
| | **Total Interest Paid - Positive** |
| Provincial vs Weighted Avg Borrowing: | **4,598** |
| Provincial vs FHT Borrowing: | **1,044** |

*ergy's methodology exactly in Developing FAA/RA. Subject to updates and refinemen*

| ng Calculation: | |
|---|---|
| 3.357% | *Source: Debt Issuance per QP Briefing* |
| 4.50% | *Source: Financing Plan Table 3* |
| 5.50% | *Source: Financing Plan Table 3* |
| **4.02%** | |

| Net Interest Paid to 2047 |
|---|
| 16,589 |
| 9,069 |
| 7,887 |
| 13,008 |

| |
|---|
| **Net Interest Paid to 2047** |
| **5,121** |
| **1,182** |

*t.*

**Table 3:**

| Tranche and Debt Type | Risk Profile | Source |
|---|---|---|
| Tranche A Senior Debt | Lowest Risk | Capital Market |
| Tranche B Subordinated Debt | Medium Risk | OPG via Provinc |
| Tranche C Junior Subordinated Debt | Highest Risk | OPG via Provinc |
| | | OPG via Capita Markets |
| Weighted Average | | |

## Indicative Pricing by Debt Tranche

| | % of Total Funding Requirement | Rating Category Estimate | Current Pricing | Potential Rating Range | Price Based on Rating Range |
|---|---|---|---|---|---|
| | 51% | AAA | 3.25% | AAA – AA | 3.25% – 3.75% |
| ce | 39% | A | 4.5% | AA – A | 4.0% – 4.5% |
| ce | 5% | BBB | 5.5% | A – BBB | 5.0% – 5.75% |
| l | 5% | | | | |
| | | | 4.0% | | 3.75% – 4.5% |

OFHP debt and interest projections, by calendar year

$ nominal million

| |
|---|
| FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment* |
| Interest Paid |
| Closing Debt Balance |

*Delta between IESO GA cost forecast and Total GA paid by ratepayer, inclusive of interest
Notes: model assumes interest rate of 4.5% and data is exclusive of OPG financing fees

*Date: October 19, 2017*
*Source: Ministry of Energy*

| Recreation by EFB |
|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** |
| ***(Exactly from above)*** |
| Interest Paid (attempted recreation) [EFB Calculation] |
| Closing Debt Balance [EFB Calculation] |

| ***Check*** |
|---|

| Alternate Method of Calculation 1) Assuming equal monthly payments and interest (componded monthly) |
|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** |
| ***(Exactly from above)*** |
| Interest Paid - In Year |
| Total Borrowing - In Year |
| Interest Paid - Previous Year Closing Balance |
| Closing Debt Balance |

| Alternate Method of Calculation 2) All borrowing at beginning of the year, compounded yearly |
|---|
| *FAA w/ Interest, Fees, Readjustment Principle Recovery, Readjustment** |
| ***(Exactly from above)*** |
| Interest Paid - In Year |
| Total Borrowing - In Year |
| Interest Paid - Previous Year Closing Balance |
| Closing Debt Balance |

| | 2017 | 2018 | 2019 | 2020 |
|---|---|---|---|---|
| - | 1,396 - | 2,189 - | 2,296 - | 2,414 |
| | 32 | 116 | 225 | 343 |
| | 1,428 | 3,733.573 | 6,254 | 9,011 |

| | | | | Year Intere |
|---|---|---|---|---|
| | | | | Total Inter |
| | Interest: | | 3.12% | Net Inte |
| | **2017** | **2018** | **2019** | **2020** |
| | (1,396) | (2,189) | (2,296) | (2,414) |
| | 22 | 80 | 154 | 233 |
| | 1,428 | 3,697 | 6,147 | 8,793 |
| | ***0.00*** | ***-36.18*** | ***-107.33*** | ***-217.73*** |

| | | | | |
|---|---|---|---|---|
| | Interest: | | 4.50% | |
| | **2017** | **2018** | **2019** | **2020** |
| | (1,396) | (2,189) | (2,296) | (2,414) |
| | 13 | 46 | 48 | 50 |
| | 1,409 | 2,235 | 2,344 | 2,464 |
| | 0 | 65 | 170 | 286 |
| | 1,409 | 3,709 | 6,223 | 8,973 |

| | | | | |
|---|---|---|---|---|
| | Interest: | | 4.50% | |
| | **2017** | **2018** | **2019** | **2020** |
| | (1,396) | (2,189) | (2,296) | (2,414) |
| | 31 | 99 | 103 | 109 |
| | 1,428 | 2,288 | 2,399 | 2,522 |
| | 0 | 64 | 170 | 286 |
| | 1,428 | 3,779 | 6,348 | 9,156 |

| | 2021 | 2022 | 2023 | 2024 | 2025 |
|---|---|---|---|---|---|
| - | 2,204 | - 1,700 | - 1,050 | - 492 | - 61 |
| | 466 | 577 | 667 | 733 | 778 |
| | 11,681 | 13,958 | 15,674 | 16,899 | 17,677 |

| | | | | |
|---|---|---|---|---|
| | | 4.50% | 16589 | |
| | | 3.357% | 9069 | |
| | | 3.12% | 7887 | |
| **st Payments Stop:** | **2043** | | | |
| **est Paid - Positive:** | **8,540** | | | |
| **erest Paid to 2047:** | **7,887** | | | |

| **2021** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|
| (2,204) | (1,700) | (1,050) | (492) | (61) |
| 314 | 385 | 441 | 480 | 504 |
| 11,311 | 13,397 | 14,888 | 15,859 | 16,424 |
| ***-369.67*** | ***-561.09*** | ***-786.58*** | ***-1039.83*** | ***-1253.5732*** |

| **2021** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|
| (2,204) | (1,700) | (1,050) | (492) | (61) |
| 46 | 36 | 22 | 10 | 1 |
| 2,250 | 1,736 | 1,072 | 502 | 62 |
| 412 | 535 | 639 | 717 | 773 |
| 11,635 | 13,905 | 15,616 | 16,836 | 17,671 |

| **2021** | **2022** | **2023** | **2024** | **2025** |
|---|---|---|---|---|
| (2,204) | (1,700) | (1,050) | (492) | (61) |
| 99 | 76 | 47 | 22 | 3 |
| 2,304 | 1,777 | 1,097 | 514 | 63 |
| 412 | 534 | 638 | 716 | 772 |
| 11,872 | 14,183 | 15,918 | 17,148 | 17,983 |

| 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|
| 79 | 129 | 354 | 714 | 1,251 |
| 814 | 851 | 883 | 896 | 888 |
| 18,491 | 19,342 | 19,904 | 19,904 | 19,541 |

| **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|
| 79 | 129 | 354 | 714 | 1,251 |
| 519 | 532 | 542 | 542 | 528 |
| 16,863 | 17,266 | 17,454 | 17,282 | 16,559 |
| ***-1627.58*** | ***-2075.81*** | ***-2450.67*** | ***-2622.75*** | ***-2982.37*** |

| **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|
| 79 | 129 | 354 | 714 | 1,251 |
| (2) | (3) | (7) | (15) | (26) |
| (81) | (132) | (362) | (729) | (1,277) |
| 812 | 845 | 878 | 902 | 910 |
| 18,402 | 19,115 | 19,631 | 19,804 | 19,437 |

| **2026** | **2027** | **2028** | **2029** | **2030** |
|---|---|---|---|---|
| 79 | 129 | 354 | 714 | 1,251 |
| (4) | (6) | (16) | (32) | (56) |
| (83) | (135) | (370) | (746) | (1,307) |
| 809 | 842 | 874 | 896 | 903 |
| 18,710 | 19,416 | 19,920 | 20,070 | 19,666 |

| 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|
| 1,188 | 1,348 | 1,419 | 1,901 | 2,087 |
| 872 | 854 | 830 | 791 | 736 |
| 19,226 | 18,732 | 18,143 | 17,033 | 15,682 |

| **2031** | **2032** | **2033** | **2034** | **2035** |
|---|---|---|---|---|
| 1,188 | 1,348 | 1,419 | 1,901 | 2,087 |
| 506 | 482 | 453 | 415 | 365 |
| 15,877 | 15,011 | 14,045 | 12,560 | 10,838 |
| ***-3348.62*** | ***-3720.82*** | ***-4097.21*** | ***-4473.63*** | ***-4844.74*** |

| **2031** | **2032** | **2033** | **2034** | **2035** |
|---|---|---|---|---|
| 1,188 | 1,348 | 1,419 | 1,901 | 2,087 |
| (25) | (28) | (30) | (40) | (44) |
| (1,213) | (1,376) | (1,449) | (1,940) | (2,131) |
| 893 | 878 | 855 | 828 | 777 |
| 19,118 | 18,620 | 18,027 | 16,914 | 15,561 |

| **2031** | **2032** | **2033** | **2034** | **2035** |
|---|---|---|---|---|
| 1,188 | 1,348 | 1,419 | 1,901 | 2,087 |
| (53) | (61) | (64) | (86) | (94) |
| (1,241) | (1,408) | (1,483) | (1,986) | (2,181) |
| 885 | 869 | 845 | 816 | 763 |
| 19,310 | 18,771 | 18,132 | 16,962 | 15,544 |

| 2036 | 2037 | 2038 | 2039 | 2040 |
|---|---|---|---|---|
| 2,128 | 2,062 | 2,099 | 1,796 | 1,527 |
| 673 | 607 | 540 | 475 | 420 |
| 14,227 | 12,773 | 11,214 | 9,893 | 8,786 |

| **2036** | **2037** | **2038** | **2039** | **2040** |
|---|---|---|---|---|
| 2,128 | 2,062 | 2,099 | 1,796 | 1,527 |
| 310 | 253 | 195 | 140 | 92 |
| 9,019 | 7,210 | 5,307 | 3,651 | 2,215 |
| ***-5207.93*** | ***-5562.25*** | ***-5906.67*** | ***-6241.82*** | ***-6570.57*** |

| **2036** | **2037** | **2038** | **2039** | **2040** |
|---|---|---|---|---|
| 2,128 | 2,062 | 2,099 | 1,796 | 1,527 |
| (44) | (43) | (44) | (38) | (32) |
| (2,173) | (2,105) | (2,142) | (1,833) | (1,559) |
| 715 | 648 | 581 | 509 | 448 |
| 14,103 | 12,646 | 11,084 | 9,760 | 8,649 |

| **2036** | **2037** | **2038** | **2039** | **2040** |
|---|---|---|---|---|
| 2,128 | 2,062 | 2,099 | 1,796 | 1,527 |
| (96) | (93) | (94) | (81) | (69) |
| (2,224) | (2,155) | (2,193) | (1,877) | (1,596) |
| 699 | 631 | 562 | 489 | 426 |
| 14,020 | 12,496 | 10,865 | 9,477 | 8,308 |

| 2041 | 2042 | 2043 | 2044 | 2045 |
|---|---|---|---|---|
| 1,392 | 1,379 | 1,310 | 1,341 | 1,357 |
| 372 | 326 | 279 | 231 | 179 |
| 7,766 | 6,713 | 5,682 | 4,571 | 3,394 |

| **2041** | **2042** | **2043** | **2044** | **2045** |
|---|---|---|---|---|
| 1,392 | 1,379 | 1,310 | 1,341 | 1,357 |
| 48 | 6 | (37) | (80) | (125) |
| 871 | (502) | (1,849) | (3,270) | (4,752) |
| ***-6894.84*** | ***-7214.86*** | ***-7530.40*** | ***-7840.94*** | ***-8145.29*** |

| **2041** | **2042** | **2043** | **2044** | **2045** |
|---|---|---|---|---|
| 1,392 | 1,379 | 1,310 | 1,341 | 1,357 |
| (29) | (29) | (27) | (28) | (28) |
| (1,421) | (1,408) | (1,337) | (1,369) | (1,385) |
| 397 | 350 | 302 | 254 | 203 |
| 7,625 | 6,568 | 5,532 | 4,417 | 3,235 |

| **2041** | **2042** | **2043** | **2044** | **2045** |
|---|---|---|---|---|
| 1,392 | 1,379 | 1,310 | 1,341 | 1,357 |
| (63) | (62) | (59) | (60) | (61) |
| (1,455) | (1,441) | (1,369) | (1,401) | (1,418) |
| 374 | 325 | 275 | 226 | 173 |
| 7,227 | 6,111 | 5,017 | 3,842 | 2,597 |

| 2046 | 2047 | Peak Debt | |
|---|---|---|---|
| 1,526 | 2,034 | | |
| 121 | 45 | 16,619 | |
| 1,989 | 0 | 19,904 | |
| | | | 8,733 |

| 2046 | 2047 | | |
|---|---|---|---|
| 1,526 | 2,034 | | |
| (175) | (237) | 7,887 | Interest Co |
| (6,452) | (8,723) | 17,454 | 3.12 |
| ***-8441.18*** | ***-8722.65*** | | |

| 2046 | 2047 | |
|---|---|---|
| 1,526 | 2,034 | |
| (32) | (42) | |
| (1,558) | (2,076) | |
| 149 | 84 | |
| 1,826 | (166) | 19,804 |

| 2046 | 2047 | |
|---|---|---|
| 1,526 | 2,034 | |
| (69) | (92) | |
| (1,595) | (2,125) | |
| 117 | 50 | |
| 1,119 | (956) | 20,070 |

sts



A TRUSTED BUSINESS PARTNER DRIVING VALUE

# OPG's Financing Outlook - Debt & Equity

March 1, 2018

ONTARIO POWER GENERATION



# Financing & Liquidity Outlook

**Financing and Liquidity Outlook - Years Ended Dec 31**

| *(in millions of dollars)* | Actual 2017 | 2018 | Business Plan 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,724** | **2,291** | **3,201** | **2,852** | **3,398** |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Development Projects | (62) | (179) | (125) | (160) | (103) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Other | 143 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Project Financing - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |

## Debt:

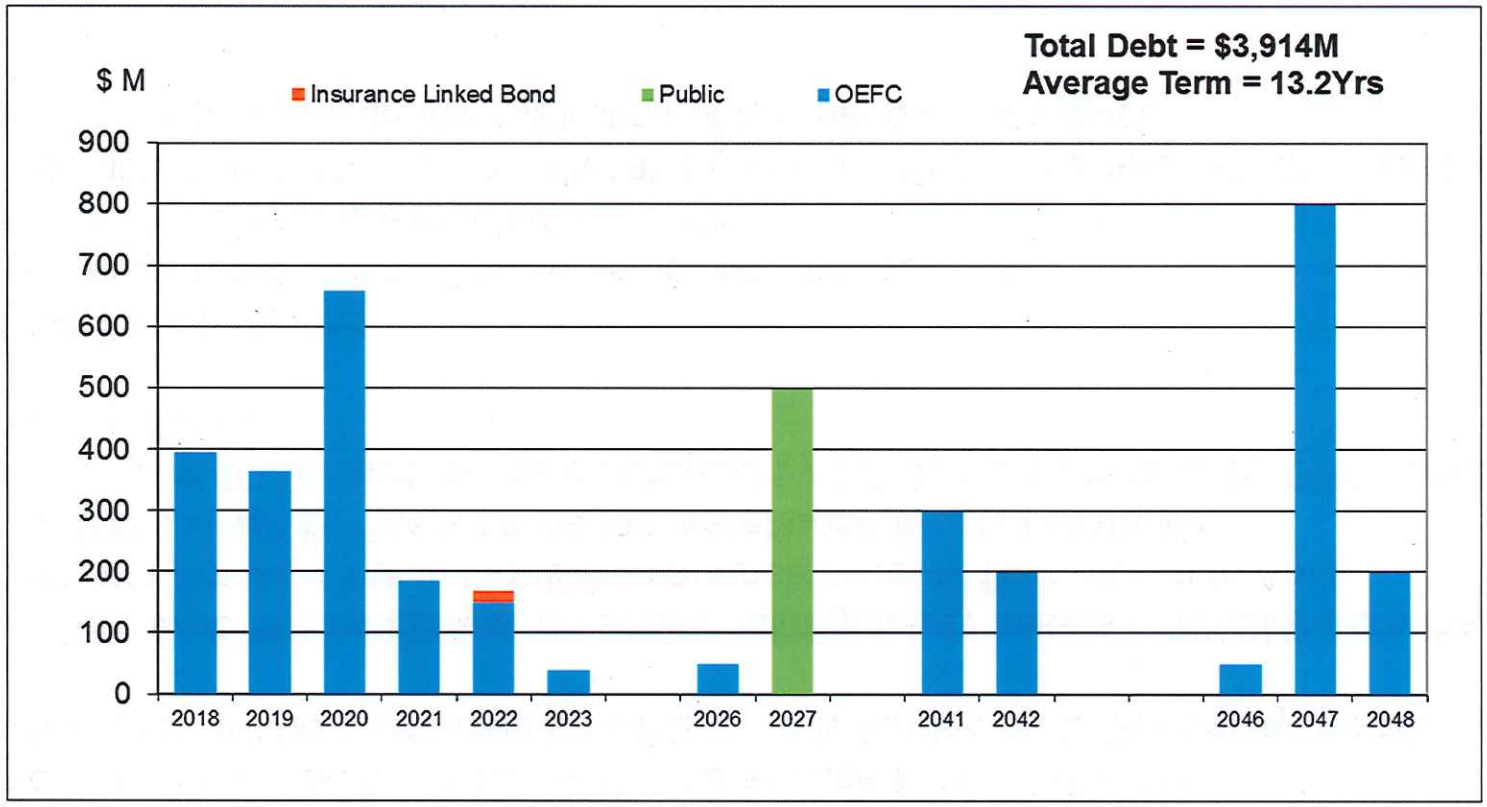
- Darlington refurbishment expenditures are expected to be ~$1.1B/yr over the next 4 years
- General corporate requirement of $1.2B in 2018
- General corporate borrowing requirement beyond 2018 is forecast to be modest, mainly due to the collection of retrospective revenue
  - Total of ~$700M for the period of 2019-2021
- $2.35B OEFC facility for 2017/2018 to refinance maturing debt and to fund Darlington refurbishment
  - $1B has been drawn
- OPG is contemplating issuing green bonds to fund Nanticoke Solar and other green initiatives

## Equity:

- OPG will issue ~$1.1B shares per year over the next 4 years, to support its subordinated debt investment in Fair Hydro Trust (FHT)

ONTARIO POWER GENERATION

# Corporate Debt Maturities




Notes:

- Of the $395M debt maturities in 2018, $75M matured in January
- Debt maturities exclude non-recourse project debt



ONTARIO POWER GENERATION



# FHT Update - Next Issuance

- By the end of March, FHT will purchase an additional ~$600M regulatory assets from the IESO
  - Represents the projected balance of IESO variance account by the end of March
  - Senior tranche will be financed via the warehouse facility (~$300M)
  - Sub tranches will be purchased by OPG, mainly funded by OFA's equity injection (~$265M)

- In April, FHT expects to purchase an additional regulatory assets (<$200M) from the IESO
  - Represents the increase in the IESO variance account from March to April
  - Senior tranche will be financed via the warehouse facility (<$100M)
  - Incremental sub tranches will be purchased by OPG, mainly funded by OFA's equity injection (<$90M)

- April Term Debt Issuance
  - Expect to term out about ~$400M senior warehouse debt
  - The term of the debt is expected to be 20yr
  - It is consistent with MOE's Fair Allocation Amount (FAA), and also reflects investors' interest as expressed during marketing of the inaugural issuance



# Appendix - FHT Senior Term Debt Offering

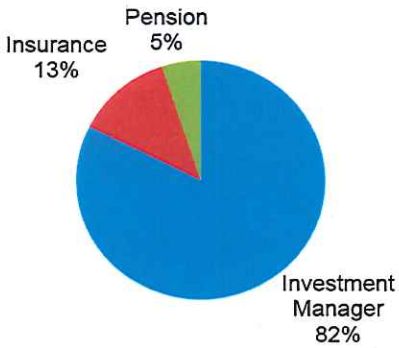
**Fair Hydro Trust**
**C$500,000,000**
Senior Notes – Series 2018-1

- Strong inaugural term debt offering with ~$1.8 billion in overall interest from 36 institutional investors across Canada
- Extensive marketing efforts (roadshows held in Toronto, Montreal, Winnipeg, and Vancouver) and clear articulation of FHT's story and objectives are key drivers for the transaction

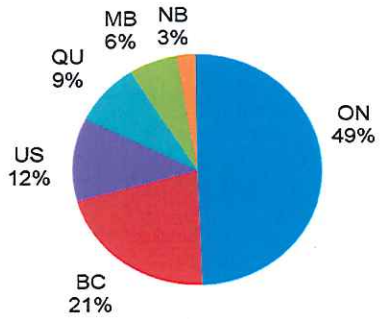
## Transaction Description

| | |
|---|---|
| Issuer: | Fair Hydro Trust |
| Settlement Date: | 09-Feb-18 |
| Ratings: | DBRS: AAA(sf)<br>Moody's: Aa2(sf) |
| Amount: | $500,000,000 |
| Coupon: | 3.357% |
| Coupon Dates: | May 15 and November 15 |
| Expected Maturity Date: | May 15, 2033 |
| Spread vs. Benchmark: | 91.9 bps |
| GoC Benchmark Yield (June 1, 2033): | 2.438% |
| Yield: | 3.357% |
| Syndicate: (*joint lead) | CIBC World Markets Inc.*, RBC Dominion Securities Inc.*, Goldman Sachs Canada Inc.*; BMO Nesbitt Burns Inc.; Morgan Stanley Canada Limited, National Bank Financial Inc., Scotia Capital Inc., TD Securities Inc., HSBC Securities (Canada) Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., Casgrain & Company Limited |

## Investor Type




## Investor Geography




| | Outstanding | | Credit Rating | |
|---|---|---|---|---|
| Term Debt (issued on February 9, 2018) | Rate | ($M) | Moody's | DBRS |
| Tranche A (51%) - Senior Debt (Capital Markets) | 3.36% | 500 | Aa2(sf) | AAA(sf) |
| Tranche B (39%) - Subordinated Debt (OPG) | 3.64% | 382 | Aa2(sf) | AA(sf) |
| Tranche C (10%) - Junior Subordinated Debt (OPG) | 3.96% | 98 | Aa2(sf) | A(sf) |
| Total (Term: 15.25 years) | | 980 | | |



ONTARIO POWER GENERATION

# 2017-19 OPG Business Plan

Submitted November 28, 2016

**CEFD Questions:**

1. In Appendix 3, Non Income Tax PILs, instead of the aggregate, please provide a breakdown of GRC Payable to OEFC and NPC individually.

2. Page 1-2 or Appendix 3:
    a) The March 31, 2017 Fiscal NI Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.
    b) Page 1 shows the 2016 Forecast of NI Attributable to Shareholder to be $438M. This is Jan 1, 2016 to Dec 31, 2016.
    c) We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?

3. What is the PIL expense without headquarter sales gain? Is there a PILs element in the $166M PIL number provided related to the headquarter sale?

4. Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "The OEB's decision on OPG's rate application is expected during the third quarter of 2017." – Even though the decision comes in late 2017, can OEB back date the effective date?

**201~~6~~7 Business Plan Forecast and New OPG outlook**

- The 201~~6~~7 Business Plan is ~~considerably better than the~~similar in projections provided by OPG's management via the Ministry of Energy in ~~January 2016~~the latest concurred 2016 Business Plan, while ~~it~~ there remains a significant drop in OPG's projected earnings before tax (EBT) in 2016-17 compared to Budget 201~~5~~6 ~~(and carried over to Budget 2016)~~ of $~~289~~ 250 million~~, versus a drop of $475 million in the January 2016 preliminary numbers.~~.
    - The preliminary explanations for the drop of OPG's EBT are related to a number of OEB regulatory risks related to the pending rate application for the 5 year period starting in 2017.
    - ~~The explanations for changes between OPG's 2016 Business Plan forecast and the January 2016 preliminary forecast are related to changes of the rate application assumptions in OPG's new business plan. Detailed explanations are currently pending.~~
- The latest projected EBT ~~results,~~ provided in OPG's ~~March version~~2017 ~~of the 2016~~ Business Plan ~~[yet to be concurred]~~, remain ~~are higher in 2017-18 and~~ relatively unchanged in 2018-19 and onwards.
- The following tables outline the EBT impacts from ~~Budget 2015 and~~ Budget 2016, as well OPG's January and 2016 March Business Plan forecasts with variance compared to the fiscal plan.

| ~~Budget 2015 (SM)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~245~~ | ~~471~~ | ~~586~~ | ~~673~~ |
| ~~Income Taxes~~ | ~~100~~ | ~~224~~ | ~~159~~ | ~~182~~ |
| ~~**Earnings Before Tax**~~ | ~~**345**~~ | ~~**695**~~ | ~~**745**~~ | ~~**855**~~ |

| **Budget 2016 ($M)** | 2015-16 | **2016-17** | **2017-18** | **2018-19** |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 257 | 471 | 586 | 673 |
| Income Taxes | 67 | 224 | 159 | 182 |
| **Earnings Before Tax** | **324** | **695** | **745** | **855** |

| **OPG's January Preliminary Planning Projections ($M)** | 2015-16 | **2016-17** | **2017-18** | **2018-19** |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 | 575 |
| Income Taxes | 89 | 120 | 250 | 140 |
| **Earnings Before Tax** | **389** | **220** | **890** | **715** |
| **EBT Variance to Fiscal Plan** | **65** | **(475)** | **145** | **(140)** |

**Commented [SQ21]:** In the OPG folder, there is no March BP…. Only May. Where are the March BP numbers coming from?

\\ofina.on.ca\ofadfs\Users\CEF\Hydro 2016\OPG\Business Plan\OPG May Business Plan

**Commented [SQ22]:** Suggest deleting column.

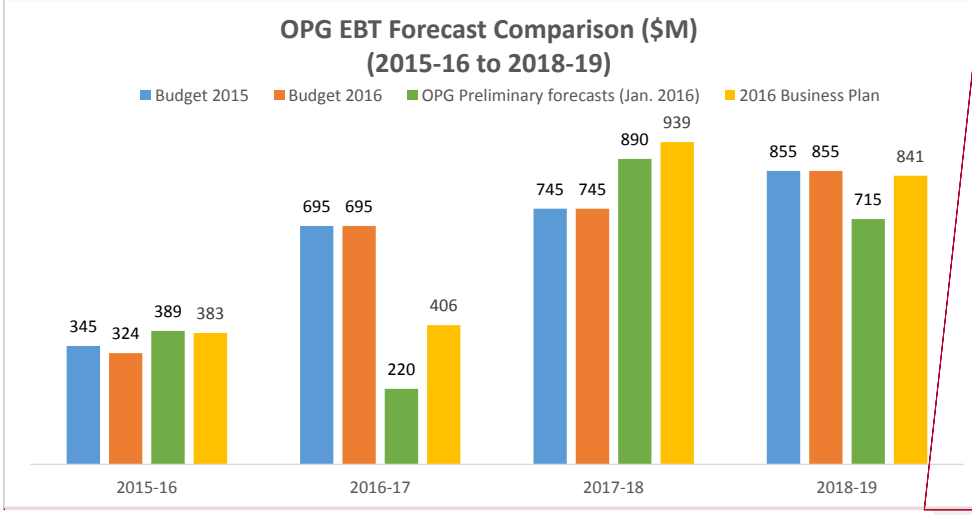
**Commented [SQ23]:** Suggest deleting column

| OPG March 2016 Business Plan ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | **383** | **406** | **939** | **841** |
| **EBT Variance to Fiscal Plan** | **59** | **(289)** | **194** | **(14)** |

**Commented [SQ24]:** In the OPG folder, there is no March BP…. Only July. Where are the March BP numbers coming from?

Z:\Users\CEF\Hydro 2016\OPG\Business Plan\OPG July Business Plan

| OPG 2017 Business Plan ($M) | | 2016-17 | 2017-18 | 2018-19 | 2020-21 |
|---|---|---|---|---|---|
| Net Income After Tax (Adjusted) | | N/A | N/A | N/A | N/A |
| Income Taxes | | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | | **445** | **868** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | | **(250)** | **123** | **(42)** | |




**Commented [SQ25]:** Updated.

- Based on 2016 OPG Business Plan, OPG's financial reports, and its monthly updates received in ~~May~~ November 2016,~~.~~ OPG's new outlook is forecast as below

| OPG New Outlook ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|

**Formatted Table**

| | | | | | |
|---|---|---|---|---|---|
| Net Income After Tax (Estimated) | 291 | ~~335~~349 | ~~551~~702 | ~~692~~678 | 726 |
| Income Taxes (Estimated) | 92 | ~~120~~96 | ~~388~~166 | ~~150~~135 | 170 |
| **Earnings Before Tax** | **383** | **~~445~~455** | **~~939~~868** | **~~841~~813** | **896** |
| **EBT Variance to Fiscal Plan** | **59** | **(240)** | **194** | **(14)** | |

***Note:***

***~~1.~~ 201~~65~~-1~~7+6~~ OPG net income and estimated Income Tax PILs ~~is~~gre ~~calculated based on OPG's 2015 annual report and 2016 Q1 financial reports. The EBT is~~ provided in OPG~~'s March~~ 201~~67~~ B~~b~~usiness ~~p~~Plan (provided in November 2016); the ~~income tax for 2015-16~~EBT is calculated by sum of the two numbers ~~the difference~~. All numbers are provided as fiscalized numbers in OPG's latest business plan.***

***~~2. 2016-17 forecast is based on OPG's monthly updates provided in May. This update came later than OPG 2016 business plan.~~***

***~~3.~~1. ~~2017-18 and 2018-19 EBT forecasts are provided in OPG March 2016 business plan; The net income forecasts are fiscalized estimates based on calendar year figures provided in the business plan; the income taxes for both years are calculated by the difference.~~***

**Commented [SQ26]:** Source? Where can we get actuals? The EBT Variance to Fiscal Plan should be N/A since this is old data for comparison purposes.

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- Other risks are likely not reflected in OPG's 201~~6~~7 Business Plan forecasts, such as the following:
  - Any Provincial Public Accounts consolidation adjustments for realised versus unrealised gains in the Ontario Nuclear Funds Agreement (ONFA) funds (upside or downside).
  - Any risks from consolidating OPG on an International Financial Reporting Standards (IFRS) basis. OPG planning and financials are on a U.S. GAAP basis.
  - Any changes in OPG projections to Gross Revenue Charge and property tax payments-in-lieu to the Province (OEFC), which are expected to be relatively small.
- OPG's 2017 Business Plan assumes that the OEB will approve OPG's rate application with an effective date of January 1, 2017. OPG expects OEB's decision in the third quarter of 2017 and makes note that should OEB set a later effective date, OPG's Net Income is expected to decrease by $60 million per month for the 2017/18 fiscal year.
- ~~There is likely a significant provision built into the forecast related to the rate application.~~
  - ~~Note that OPG typically does not include in its business plan specific details on risks, as the OEB is expected to review its business plan.~~

**2017~~6~~ Business Plan Forecast and New OPG outlook**

- The 2016~~7~~ Business Plan is ~~considerably better than the~~similar in projections provided ~~by OPG's management via the Ministry of Energy~~ in ~~January 2016~~the ~~latest concurred~~ 2016 Business Plan, while ~~it~~ there remains a significant drop in OPG's projected earnings before tax (EBT) in 2016-17 compared to Budget 2015~~6~~ ~~(and carried over to Budget 2016)~~ of $~~289~~ 250 million~~, versus a drop of $475 million in the January 2016 preliminary numbers.~~.
    - The 2016-18 Business Plan formed the basis of OPG's rate filing with OEB and many of those assumptions and inputs continue to be reflected in this 2017-19 Business Plan.
    - The preliminary explanations for the drop of OPG's EBT are related to a number of OEB regulatory risks related to the pending decision on the rate application for the 5 year period starting in 2017. A decision has been deferred to Q3 2017.
    - ~~The explanations for changes between OPG's 2016 Business Plan forecast and the January 2016 preliminary forecast are related to changes of the rate application assumptions in OPG's new business plan. Detailed explanations are currently pending.~~
- The latest projected EBT ~~results,~~ provided in OPG's ~~March version~~2017 ~~of the 2016~~ Business Plan ~~[yet to be concurred]~~, remain ~~are higher in 2017-18 and~~ relatively unchanged in 2018-19 and onwards.
- The following tables outline the EBT impacts from ~~Budget 2015 and~~ Budget 2016, as well OPG's January and 2016 March Business Plan forecasts with variance compared to the fiscal plan.

| ~~Budget 2015 ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~245~~ | ~~471~~ | ~~586~~ | ~~673~~ |
| ~~Income Taxes~~ | ~~100~~ | ~~224~~ | ~~159~~ | ~~182~~ |
| ~~**Earnings Before Tax**~~ | ~~**345**~~ | ~~**695**~~ | ~~**745**~~ | ~~**855**~~ |

| **Budget 2016 ($M)** | **2016-17** | **2017-18** | **2018-19** | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Taxes | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

**Commented [SQ21]:** In the OPG folder, there is no March BP…. Only May. Where are the March BP numbers coming from?

\\ofina.on.ca\ofadfs\Users\CEF\Hydro 2016\OPG\Business Plan\OPG May Business Plan

| ~~OPG's January Preliminary Planning Projections ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~300~~ | ~~100~~ | ~~640~~ | ~~575~~ |
| ~~Income Taxes~~ | ~~89~~ | ~~120~~ | ~~250~~ | ~~140~~ |
| ~~**Earnings Before Tax**~~ | ~~**389**~~ | ~~**220**~~ | ~~**890**~~ | ~~**715**~~ |
| ~~**EBT Variance to Fiscal Plan**~~ | ~~**65**~~ | ~~**(475)**~~ | ~~**145**~~ | ~~**(140)**~~ |

**Commented [SQ22]:** Suggest deleting column

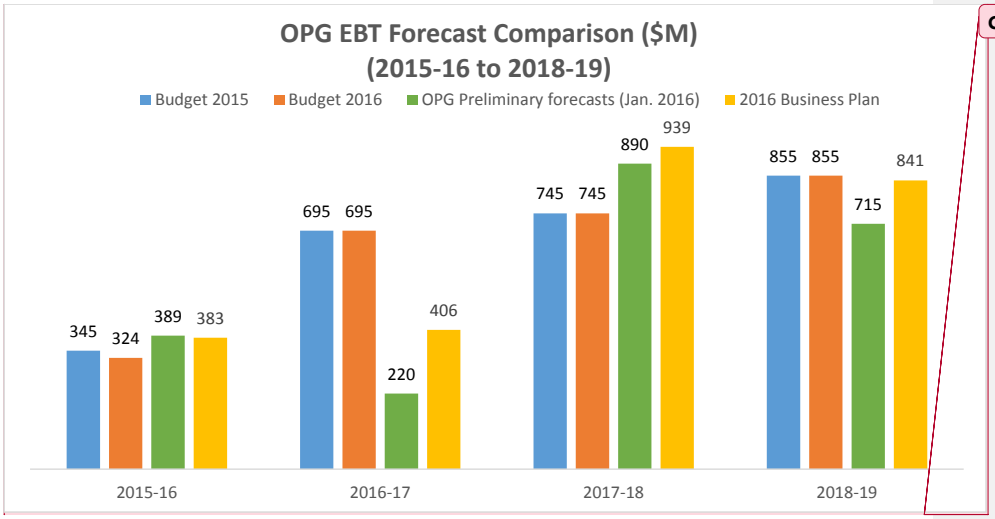
| **OPG ~~March~~ July 2016 Business Plan ($M)** | **2015-16** | **2016-17** | **2017-18** | **2018-19** |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | **383** | **406** | **939** | **841** |
| **EBT Variance to Fiscal Plan** | **59** | **(289)** | **194** | **(14)** |

**Commented [SQ23]:** In the OPG folder, there is no March BP…. Only July. Where are the March BP numbers coming from?

Z:\Users\CEF\Hydro 2016\OPG\Business Plan\OPG July Business Plan

**Commented [GH4R3]:** I think using July's BP is better.

| **OPG 2017 Business Plan ($M)** | | **2016-17** | **2017-18** | **2018-19** | **201920-201** |
|---|---|---|---|---|---|
| Net Income After Tax (Adjusted) | | N/A | N/A | N/A | N/A |
| Income Taxes | | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | | **445** | **868** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | | **(250)** | **123** | **(42)** | |




**Commented [SQ25]:** Updated.

- Based on 2016 OPG Business Plan, OPG's financial reports, and its monthly updates received in ~~May~~ November 2016~~.~~, OPG's new outlook is forecast as below

| OPG New Outlook ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| Net Income After Tax (Estimated) | 291 | ~~335~~349 | ~~551~~702 | ~~692~~678 | 726 |
| Income Taxes (Estimated) | 92 | ~~120~~96 | ~~388~~166 | ~~150~~135 | 170 |
| **Earnings Before Tax** | **383** | **~~445~~455** | **~~939~~868** | **~~841~~813** | **896** |
| **EBT Variance to Fiscal Plan** | 59 | **(240)** | **194** | **(14)** | |

***Note:***

***~~1.~~ 201~~65~~-1~~7+6~~ OPG net income and estimated Income Tax PILs ~~is~~are ~~calculated based on OPG's 2015 annual report and 2016 Q1 financial reports. The EBT is~~ provided in OPG~~'~~s ~~March~~ 201~~6~~7 B~~b~~usiness ~~p~~Plan (provided in November 2016); the ~~income tax for 2015-16~~EBT is calculated by sum of the two numbers ~~the difference~~. All numbers are provided as fiscalized numbers in OPG's latest business plan.***

***~~2. 2016-17 forecast is based on OPG's monthly updates provided in May. This update came later than OPG 2016 business plan.~~***

***~~3.~~1. ~~2017-18 and 2018-19 EBT forecasts are provided in OPG March 2016 business plan; The net income forecasts are fiscalized estimates based on calendar year figures provided in the business plan; the income taxes for both years are calculated by the difference.~~***

- Other risks are likely not reflected in OPG's 201~~6~~7 Business Plan forecasts, such as the following:
  - Any Provincial Public Accounts consolidation adjustments for realised versus unrealised gains in the Ontario Nuclear Funds Agreement (ONFA) funds (upside or downside).
  - Any risks from consolidating OPG on an International Financial Reporting Standards (IFRS) basis. OPG planning and financials are on a U.S. GAAP basis.
  - Any changes in OPG projections to Gross Revenue Charge and property tax payments-in-lieu to the Province (OEFC), which are expected to be relatively small.
- OPG's 2017 Business Plan assumes that the OEB will approve OPG's rate application with an effective date of January 1, 2017. OPG expects OEB's decision in the third quarter of 2017 and makes note that should OEB set a later effective date, OPG's Net Income is expected to decrease by $60 million per month for the 2017/18 fiscal year.

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**Commented [SQ26]:** Source? Where can we get actuals? The EBT Variance to Fiscal Plan should be N/A since this is old data for comparison purposes.

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- ~~There is likely a significant provision built into the forecast related to the rate application.~~
    - ~~Note that OPG typically does not include in its business plan specific details on risks, as the OEB is expected to review its business plan.~~

**2017 Business Plan Forecast and New OPG outlook**

- The 2017 Business Plan is similar in projections provided in the 2016 Business Plan, while there remains a significant drop in OPG's projected earnings before tax (EBT) in 2016-17 compared to Budget 2016 of $250 million.
    - The 2016-18 Business Plan formed the basis of OPG's rate filing with OEB and many of those assumptions and inputs continue to be reflected in this 2017-19 Business Plan.
    - The preliminary explanations for the drop of OPG's EBT are related to a number of OEB regulatory risks related to the pending decision on the rate application for the 5 year period starting in 2017. A decision has been deferred to Q3 2017.
- The latest projected EBT provided in OPG's 2017 Business Plan, remain relatively unchanged in 2018-19 and onwards.
- The following tables outline the EBT impacts from Budget 2016, as well OPG's January and 2016 March Business Plan forecasts with variance compared to the fiscal plan.

| Budget 2016 ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Taxes | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

| OPG July 2016 Business Plan ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | **383** | **406** | **939** | **841** |
| **EBT Variance to Fiscal Plan** | **59** | **(289)** | **194** | **(14)** |

| OPG 2017 Business Plan ($M) | | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| Net Income After Tax (Adjusted) | | N/A | N/A | N/A | N/A |
| Income Taxes | | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | | **445** | **868** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | | **(250)** | **123** | **(42)** | |

**Commented [j1]:** Pls. standardize the tables so that we can compare across the figures by year.

**Commented [SQ22]:** In the OPG folder, there is no March BP…. Only May. Where are the March BP numbers coming from?

\\ofina.on.ca\ofadfs\Users\CEF\Hydro 2016\OPG\Business Plan\OPG May Business Plan

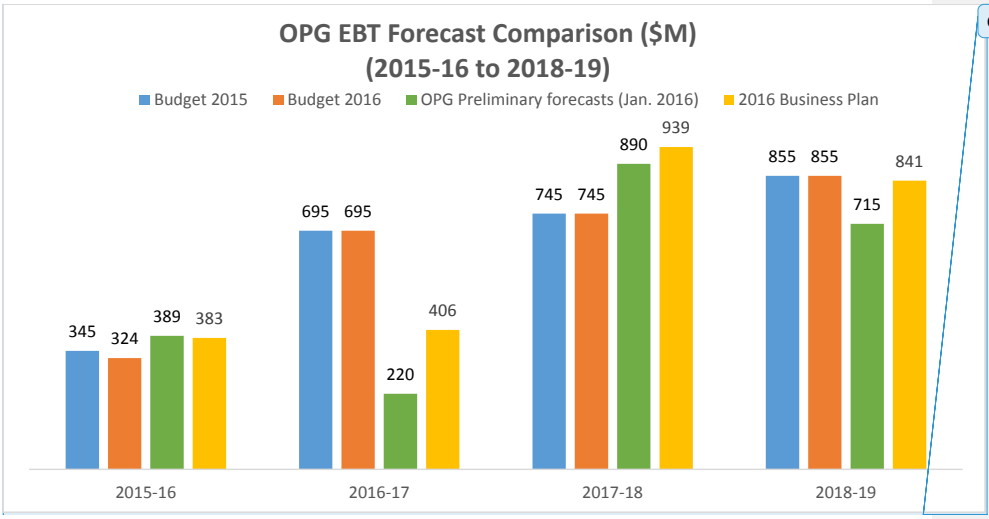
**Commented [SQ23]:** In the OPG folder, there is no March BP…. Only July. Where are the March BP numbers coming from?

Z:\Users\CEF\Hydro 2016\OPG\Business Plan\OPG July Business Plan

**Commented [GH4R3]:** I think using July's BP is better.

**Commented [j5]:** Is this figure with the OPG head office proceeds, which is baked into the AO line, taken out?

**Commented [j6]:** Same question as above, is this with the OPG head office figure taken out?




**Commented [SQ27]:** Updated.

- Based on 2016 OPG Business Plan, OPG's financial reports, and its monthly updates received in November 2016, OPG's new outlook is forecast as below

| OPG New Outlook ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| Net Income After Tax (Estimated) | 291 | 349 | 702 | 678 | 726 |
| Income Taxes (Estimated) | 92 | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **383** | **445** | **868** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | **59** | **(240)** | **194** | **(14)** | |

***Note:***

1. ***2016-17+ OPG net income and estimated Income Tax PILs are provided in OPG's 2017 Business Plan (provided in November 2016); the EBT is calculated by sum of the two numbers. All numbers are provided as fiscalized numbers in OPG's latest business plan.***

**Commented [SQ28]:** Source? Where can we get actuals? The EBT Variance to Fiscal Plan should be N/A since this is old data for comparison purposes.

- Other risks are likely not reflected in OPG's 2017 Business Plan forecasts, such as the following:
    - Any Provincial Public Accounts consolidation adjustments for realised versus unrealised gains in the Ontario Nuclear Funds Agreement (ONFA) funds (upside or downside).

- Any risks from consolidating OPG on an International Financial Reporting Standards (IFRS) basis. OPG planning and financials are on a U.S. GAAP basis.
- Any changes in OPG projections to Gross Revenue Charge and property tax payments-in-lieu to the Province (OEFC), which are expected to be relatively small.

- OPG's 2017 Business Plan assumes that the OEB will approve OPG's rate application with an effective date of January 1, 2017. OPG expects OEB's decision in the third quarter of 2017 and makes note that should OEB set a later effective date, OPG's Net Income is expected to decrease by $60 million per month for the 2017/18 fiscal year.

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projections submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The key drivers of the variances include the following:

- As noted above, the current fiscal plan estimates include estimates at the time of OPG's 2015 business plan. On May 27, 2016, OPG submitted its rate application for 2017-2021 payment amounts for its prescribed facilities to the Ontario Energy Board (OEB). The current estimates of OPG's contributions to the fiscal plan are based on OPG's 2017-19 business plan reflecting its current expectations, including OPG's current expectations on key regulatory risks.
- ~~[Insert bullets to explain variances in each year.]~~
-
    - The delay in OPG's previously planned rate application in 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017 has~~d~~ an adverse impact of about $100 million.
    - The current production outlook is lower than the forecast at the time of OPG's 2015 business plan due to factors such as incremental planned outage at the Pickering station to enable continued operations announced in January 2016, as well as additional forecast outages in OPG's hydroelectric stations.
- ~~In its rate decision for OPG's 2014 and 2015 rates, the Ontario Energy Board's (OEB) decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates has put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.~~
    - There is a risk that a portion of Darlington Refurbishment Project's assets coming into service (about $700-800 million) may be disallowed. A portion of the expenditures on the heavy water (D2O) storage facility (which totalled about $300 million) may be at greater risk of being disallowed.
    - In addition, in its rate decision for OPG's 2014 and 2015 rates, OEB's decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates will put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements

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versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.

As mentioned above ~~Note that~~ the 2017-18 forecasts in the 2017-19 Business Plan have had preliminary staff adjustments for fiscal planning purposes to remove for this table the projected pre-tax gain of $296 million included in OPG's business plan from the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note also that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
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| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
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- Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
- OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
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- Use OPG public debt to reduce Provincial debt through public financing strategy.
    - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.
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**Corporate and Electricity Finance Division**
**January ~~16~~18, 2017**

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### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projections submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The key drivers of the variances include the following:

- As noted above, the current fiscal plan estimates include estimates at the time of OPG's 2015 business plan. On May 27, 2016, OPG submitted its rate application for 2017-2021 payment amounts for its prescribed facilities to the Ontario Energy Board (OEB). The current estimates of OPG's contributions to the fiscal plan are based on OPG's 2017-19 business plan reflecting its current expectations, including OPG's current expectations on key regulatory risks.
- ~~[Insert bullets to explain variances in each year.]~~
  - The delay in OPG's previously planned rate application in 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017 had an adverse impact of about $100 million.
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- The sale of OPG's head office is on track for 2017-18 fiscal year.
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**Corporate and Electricity Finance Division**
**January ~~16~~18, 2017**

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projections submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The key drivers of the variances include the following:

- As noted above, the current fiscal plan estimates include estimates at the time of OPG's 2015 business plan. On May 27, 2016, OPG submitted its rate application for 2017-2021 payment amounts for its prescribed facilities to the Ontario Energy Board (OEB). The current estimates of OPG's contributions to the fiscal plan are based on OPG's 2017-19 business plan reflecting its current expectations, including OPG's current expectations on key regulatory risks.
- ~~[Insert bullets to explain variances in each year.]~~
  - The delay in OPG's previously planned rate application in 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017 has~~d~~ an adverse impact of about $100 million.
  - The current production outlook is lower than the forecast at the time of OPG's 2015 business plan due to factors such as incremental planned outage at the Pickering station to enable continued operations announced in January 2016, as well as additional forecast outages in OPG's hydroelectric stations.
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  - In addition, in its rate decision for OPG's 2014 and 2015 rates, OEB's decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates will put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.



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Chart 1
Forecast Nuclear In-service Capital Additions* ($M)
*Amounts may not add due to rounding.

| | Reference | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
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| Nuclear operations capital projects | Ex. D2-1-3 Table 4, line 17 & 26 | 497.0 | 389.0 | 315.2 | 239.3 | 300.4 | 215.6 |
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| Support services capital projects entering rate base | Nuclear Portion of Ex. D3-1-2 Table 3, lines 7 & 13 & 15 | 10.5 | 8.1 | 18.0 | 5.0 | 5.0 | 5.0 |
| **Total nuclear in-service additions, excluding ARC** | Ex. B3-3-1 Table 1 & 2, col [b] | **857.9** | **771.5** | **342.1** | **244.3** | **5,114.7** | **221.1** |

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**Commented [AP9R8]:** For 2014-2015, it is about $230M per year ($461M) total. But the difference declines to just under $50M a year in 2021. The ability for OPG to recover the OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account is pending the outcome of the OEB's ...

Note that the 2017-18 forecasts in the 2017-19 Business Plan have had preliminary staff adjustments for fiscal planning purposes to remove for this table the projected pre-tax gain of $296 million included in OPG's business plan from the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note also that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

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**Key Risks**

*OEB's decision on OPG's 2016 rate application*

- The OPG business plan reflects its rate application, which includes OPG rate increases of about 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about half of a typical bill, and OPG generation accounts for about half of total commodity costs.)
    - E.g., for each $1 per megawatt-hour (MWh) reduction in OPG's nuclear rate, OPG's projected financial results would decrease by about ~~$xx~~ 40 million, and for each $1 per MWh reduction in the regulated hydroelectric rate, OPG's resuls would be ~~$xx~~ 30 million lower.
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.

**Commented [RK10]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has OPG asked for an effective date for its new rates, and, if so, has the OEB agreed?

Is the effective date a risk to the projections?

Does OPG`s BP assume retroactive application so 16-17 includes an accrued amount for new rates to approved in 2017:Q3?

**Commented [AP11]:** BP assumes effective date in application is January 1 , 2017. It seems that OPG has not yet asked for interim rates, but they will likely do that during the first hearings (will be considered a preliminary matter) similar to what Hydro One did during the November 24, 2016 hearing for EB-2016-0160 (got interim rates as of January 1, 2017 due to proceedings surpassing that date).

**Commented [AP12]:** BP states it is within OEB's authority to set a later effective date, which would negatively impact OPG's monthly income by ~$50M to $60M per month for the 2017/2018.

**Commented [AP13]:** The prior rate application for OPG was late (complete version filed December 2013) and approved November 2014. The OEB had interim rates set but had the effective dates for Nuclear and previously regulated rates set in November 2014 with no retrospective application.

**Commented [AP14]:** The BP states that "as at December 31, 2017, accounts receivables includes accrued revenues for new regulated rates for the period from January 1, 2017 to the implementation date of the OEB's decision, which is assumed to be received in the third quarter of 2017. The accrued balance is assumed to be fully collected by the end of 2018." Thus, it does assume an accrued amount for new rates.

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**Corporate and Electricity Finance Division**
**January ~~16~~18, 2017**

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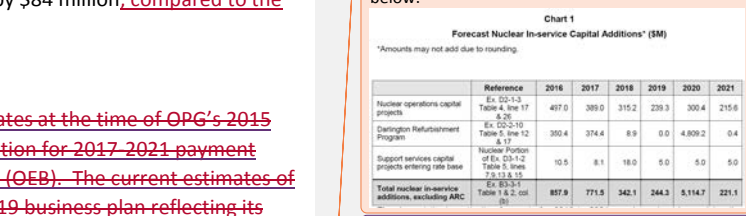


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Forecast Nuclear In-service Capital Additions* ($M)
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- Increased prudence to reflect higher risks related to OPG's rate application (see risk section below).

Note that the 2017-18 forecasts in the 2017-19 Business Plan have had preliminary staff adjustments for fiscal planning purposes to remove for this table the projected pre-tax gain of $296 million included in OPG's business plan in 2017 from the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

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- The OPG business plan reflects its rate application, which includes OPG rate increases of about 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about half of a typical bill, and OPG generation accounts for about half of total commodity costs.)

**Commented [JK8]:** Any mention of this in the rate application?

**Commented [AP9R8]:** For 2014-2015, it is about $230M per year ($461M) total. But the difference declines to just under $50M a year in 2021. The ability for OPG to recover the OPG's Pension & OPEB Cash Versus Accrual Differential Deferral Account is pending the outcome of the OEB's generic consultation on pension and OPEB. The total balance of the variance account is just over $300M in 2015 year-end.


Chart 3
Pension and OPEB Accrual-Cash Differential Amounts – Nuclear[1] ($M)

| | 2013 Actual | 2014 Actual | 2015 Actual | 2016 Projection | 2017 Plan | 2018 Plan | 2019 Plan | 2020 Plan | 2021 Plan |
|---|---|---|---|---|---|---|---|---|---|
| Pension | 133.8 | 130.3 | 129.5 | 111.3 | 51.7 | (5.0) | (27.3) | (17.2) | (30.7) |
| OPEB | 144.9 | 91.6 | 109.7 | 96.0 | 93.7 | 90.1 | 86.8 | 82.9 | 80.5 |
| Total | 278.7 | 221.9 | 239.6 | 207.3 | 145.4 | 82.1 | 59.5 | 65.7 | 49.8 |

- E.g., for each $1 per megawatt-hour (MWh) reduction in OPG's nuclear rate, OPG's projected financial results would decrease by about $~~xx~~ 40 million, and for each $1 per MWh reduction in the regulated hydroelectric rate, OPG's resuls would be $~~xx~~ 30 million lower.

- There is a risk that a portion of Darlington Refurbishment Project's assets coming into service (about $700-800 million) may be disallowed. A portion of the expenditures on the heavy water (D2O) storage facility and other Campus Plan Projects (which totalled about $300 million) may be at greater risk of being disallowed.
- In addition, in its rate decision for OPG's 2014 and 2015 rates, OEB's decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates will put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
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  - The business plan also ~~does not assume retroactive application for the rates, but does~~ hasve the recognition of regulatory assets for the portion of the nuclear revenue requirement deferred for future recovery under nuclear rate smoothing starting in 2017.

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  - OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.



**Commented [AP10]:** This seems like a reasonable estimate. As there were several intervenor opposition of OPG including some DRP capital additions in the 2014-2015 application. OPG's argument that those additions were not wholly related to the DRP but useful to on-going operations was accepted by the Board. Total in-service additions up to the in-service date in 2020 are $700m to $800M as shown below:

Chart 1
Forecast Nuclear In-service Capital Additions* ($M)
*Amounts may not add due to rounding.

| | Reference | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| Nuclear operations capital projects | Ex. D2-1-3 Table 4, line 17 & 26 | 497.0 | 389.0 | 315.2 | 239.3 | 300.4 | 215.6 |
| Darlington Refurbishment Program | Ex. D2-2-10 Table 5, line 12 & 17 | 350.4 | 374.4 | 8.9 | 0.0 | 4,809.2 | 0.4 |
| Support services capital projects entering rate base | Nuclear Portion of Ex. D3-1-2 Table 5, lines 7,9,13 & 15 | 10.5 | 8.1 | 18.0 | 5.0 | 5.0 | 5.0 |
| Total nuclear in-service additions, excluding ARC | Ex. B3-3-1 Table 1 & 2, col (h) | 857.9 | 771.5 | 342.1 | 244.3 | 5,114.7 | 221.1 |

**Commented [JK11]:** Any mention of this in the rate application?

**Commented [AP12R11]:** From the 2014-2015 decision: While Board staff agreed with the proposed amounts to be added to rate base for 2014 and 2015, they cautioned tha ...

**Commented [AP13R11]:** D20 is over budget, so this year application will test was prudent in their construction.

**Commented [AP14R11]:** Original amount was $108.1M for the whole project.

**Commented [AP15R11]:** D20 was not $300M, that was for the total campus plan projects. EB-2-13-0321 Exhibit D2 (updated version)

**Commented [SK716]:** From prior Business Plan Briefing Note.

**Commented [JK17]:** Any mention of this in the rate application?

**Commented [AP18R17]:** For 2014-2015, it is about $230M per year ($461M) total. But the difference declines to just under $50M a year in 2021. The ability for OPG to ...

**Commented [RK19]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has O ...

**Commented [AP20]:** BP assumes effective date in application is January 1 , 2017. It seems that OPG has not yet asked for interim rates, but they will likely do that ...

**Commented [AP21]:** BP states it is within OEB's authority to set a later effective date, which would negatively impa ...

**Commented [AP22]:** The prior rate application for OPG was late (complete version filed December 2013) and approved November 2014. The OEB had interim rates set ...

**Commented [AP23]:** The BP states that "as at December 31, 2017, accounts receivables includes accrued revenues for new regulated rates for the period from January 1, 201 ...

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The key drivers of the variances include the following:

- The one-year delay in OPG's previously planned rate application timing (from 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017) had an adverse impact of about $100 million as OPG previously assumed a rate increase in 2016.
- The current production outlook is lower than the forecast at the time of OPG's 2015 business plan due to factors such as incremental planned outage days at the Pickering station to enable work required to implement the planned continued operations for a few years beyond about 2020, announced in January 2016, as well as additional forecast outages in OPG's hydroelectric stations.
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    - *CEFD Staff Comments*: On November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.

- Total long-term debt for general corporate (i.e., financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017. [The actual borrowing under the facility was $0.1 billion in 2016.]
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with the first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.
        - The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.
- OPG presented 4 proposals in the Business Plan to provide greater shareholder value and keeping electricity prices low. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
    - Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
        - *CEFD Staff Comments:* OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Therefore, OPG is referring to a higher measured percentage rate of return being higher, not higher net income. For the same net income, with lower equity, the ROE percentage would be higher. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
    - Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
    - OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
        - *CEFD Staff comment:* Dividends are not revenues to the Province. OPG's net income is. Using the dividend cash for rate mitigation would have a dollar-for-dollar fiscal impact upfront, plus an IOD impact.
    - Use OPG public debt to reduce Provincial debt through public financing strategy.
        - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.
            - *CEFD Staff comment:* To-date, the government has not permitted OPG to borrow in public capital markets for general corporate purposes. OPG borrowing on its own would likely have a negative fiscal impact as its cost of borrowing is expected to be higher than the Provincee's.

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its ~~Board-approved~~ 2017-19 Business Plan ("Business Plan") to the Minister of Energy. This Business Plan is similar to the previous 2016-18 Business Plan, which was enclosed in OPG's 2017-2021 rate application, submitted to the Ontario Energy Board (OEB) on May 27, 2016, ~~excluding for~~ notwithstanding the red~~e~~acted portions ~~redacted~~.

### Fiscal Impacts

~~[Quick blurb]~~The following tables provides a comparision between Budget 2016 and the latest financial ~~information~~ projectsions submitted by OPG in its 2017-19 Business Plan. ~~OPG is now forecasting~~ Earnings Before Tax ~~will be~~ is now forecasted to be lower by $250 million in 2016-17, ~~higher~~lower in 2017-18 by $~~123~~173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments to account for the pre-tax gain on the sale of OPG headquarters.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs~~es~~ | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

| OPG 2017-~~19~~ Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | ~~N/A~~349 | ~~N/A~~~~70~~24 06* | ~~N/A~~678 | ~~N/A~~726 |
| Income Tax PILs~~es~~ | ~~N/A~~96 | ~~N/A~~166** | ~~N/A~~135 | ~~N/A~~170 |
| **Earnings Before Tax** | **445** | **572*** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | **(250)** | **(173)**** | **(42)** | **84** |

* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M.
** Income Tax PILs do not have OPG head office sale backed out. Further details required from OPG.
*** Budget 2016/Fiscal Plan included OPG headquarter sales in 2016-17 which was deferred to 2017-18 in the 2017 Business Plan, and impacts removed in the above table.

### Key Highlights

*Fiscal and Rate Payer Impacts*

- The Business Plan is largely unchanged in terms of commitments for Net Income. Consistent with the previous plan, the Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.

**Commented [j1]:** Let's minimize this as it was sent as a preliminary BP.

**Commented [SK62R1]:** Deleted. Done.

**Commented [j3]:** Same question as above, is this with the OPG head office figure taken out?

**Commented [SK64R3]:** Adjusted to take out the OPG head office. Note, we haven't adjusted to the PILs impacts. Will need to get details from OPG.

- The rate application results in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill.

- The decision for OPG's rate application is not expected until Q3 2017, so the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016-17 fiscal year.

*Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs ~~from customers~~ on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.
  - There will be a significant financial impact if OPG needs to permanently collect pension and OPEB costs on cash basis.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*Executive Compensation Framework*

- OPG's current management compensation restraint initiatives have made attracting and retaining talent a challenge. ~~Consistent with OPG's previous update,~~ OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50th percentile of market peers. ~~The ECF includes medium term incentives, which are 100% pay at risk, based on measures on 1) return on equity; 2) total generating cost; and 3) progress in execution of Darlington Refurbishemnt Unit 2.~~
  - Note: In November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e. financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017.

**Commented [SK65]:** Need to clarify. Are these general revenues collected from customers?

**Commented [SK66R5]:** Suggest deleting for simiplicity.

**Commented [SK67]:** Suggest deleting. Recently announced TBS bulletin notes changes to Executive Compensation Framework, particularly in light of nuclear: https://news.ontario.ca/tbs/en/2016/11/ontario-updating-executive-compensation-framework.html

**Commented [j8]:** Could EFB get a handle on the actdual figures from SIFB? Not necessarily for inclusion here in the note or the Outlook.

**Commented [SK69R8]:** Updated in outlook. Also made this adjustment in the OPG fiscal impact table above.

- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.
        - The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.

- OPG ~~included~~ presented 4 proposals in the Business Plan to provide greater sharedholer value and keeping electricity prices low ~~in the Business Plan, which are:~~. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
    1. Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
        - OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
    2. Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
    3. OPG to establish a dividend program tied to key business outcomes, which ~~will~~ could ~~bring~~ return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
    4. Use OPG public debt to reduce Provincial debt through public financing strategy.
        - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.

**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations.
    - Furthermore a delay in the effective date of the newly regulated rates ~~The outcome of rate application will~~ might ~~have negative impact on~~ reduce OPG's net income ~~,~~ by approximately $50 million to $60 million per month, for the 2017-18 fiscal year~~,~~. ~~if OEB postponed the effective date of OPG's proposed new regulated rates.~~ The Business Plan assumes an effective date of the newly regulated rates ~~at the~~ on ~~beginning of~~ January 1, 2017.

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**Commented [j10]:** Pickering is not to 2024? Pls. confirm and comment as to why this deviates from the earlier announcement.

**Commented [SK611R10]:** Refers to the accounting treatment (depreciation) based on the latest rate application.

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**Commented [j12]:** Wouldn't getting the equity close to the deemed ration lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

**Commented [SK613R12]:** The OEB assigns the rates based on deemed capital structure, not actual capital structure. As a result, if OPG has higher equity (than deemed) and lower debt levels (than deemed), the return on equity isn't adjusted for this higher level. Furthermore, equity is compensated at a higher rate than debt, and

**Commented [j14]:** Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [SK615R14]:** The dividend would be provided to the province. The province would have the option to direct cash inflow to lower electricity prices.

**Commented [j16]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.
- Risks from reporting OPG on an IFRS basis. OPG planning and financials are on a U.S. GAAP basis.

## 2017 Business Plan Forecast and New OPG outlook

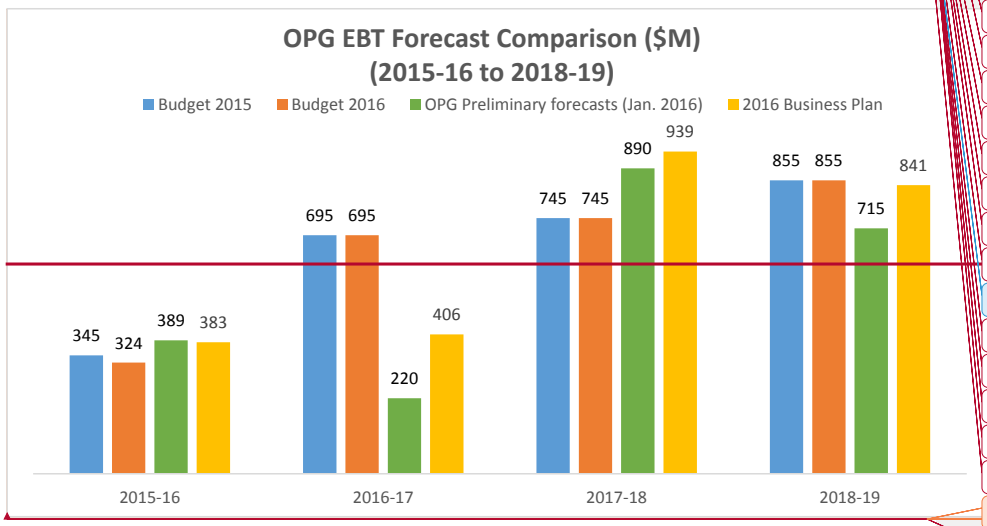
- The 2017 Business Plan is similar in projections provided in the 2016 Business Plan, while there remains a significant drop in OPG's projected earnings before tax (EBT) in 2016-17 compared to Budget 2016 of $250 million.
    - The 2016-18 Business Plan formed the basis of OPG's rate filing with OEB and many of those assumptions and inputs continue to be reflected in this 2017-19 Business Plan.
    - The preliminary explanations for the drop of OPG's EBT are related to a number of OEB regulatory risks related to the pending decision on the rate application for the 5 year period starting in 2017. A decision has been deferred to Q3 2017.
- The latest projected EBT provided in OPG's 2017 Business Plan, remain relatively unchanged in 2018-19 and onwards.
- The following tables outline the EBT impacts from Budget 2016, as well OPG's January and 2016 March Business Plan forecasts with variance compared to the fiscal plan.

| Budget 2016 ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Taxes | 224 | 159 | 182 | 108 |
| Earnings Before Tax | 695 | 745 | 855 | 812 |

| OPG July 2016 Business Plan ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| Earnings Before Tax | 383 | 406 | 939 | 841 |
| EBT Variance to Fiscal Plan | 59 | (289) | 194 | (14) |

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| OPG 2017 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| Earnings Before Tax | 445 | 868 | 813 | 896 |
| EBT Variance to Fiscal Plan | (250) | 123 | (42) | |




- Based on 2016 OPG Business Plan, OPG's financial reports, and its monthly updates received in November 2016, OPG's new outlook is forecast as below

| OPG New Outlook ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|---|
| Net Income After Tax (Estimated) | 291 | 349 | 702 | 678 | 726 |
| Income Taxes (Estimated) | 92 | 96 | 166 | 135 | 170 |
| Earnings Before Tax | 383 | 445 | 868 | 813 | 896 |
| EBT Variance to Fiscal Plan | 59 | (240) | 194 | (14) | |
| Note: | | | | | |

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1. ~~*2016-17+ OPG net income and estimated Income Tax PILs are provided in OPG's 2017 Business Plan (provided in November 2016); the EBT is calculated by sum of the two numbers. All numbers are provided as fiscalized numbers in OPG's latest business plan.*~~

- ~~Other risks are likely not reflected in OPG's 2017 Business Plan forecasts, such as the following:~~

  - ~~Any Provincial Public Accounts consolidation adjustments for realised versus unrealised gains in the Ontario Nuclear Funds Agreement (ONFA) funds (upside or downside).~~

  - ~~Any risks from consolidating OPG on an International Financial Reporting Standards (IFRS) basis. OPG planning and financials are on a U.S. GAAP basis.~~

  - ~~Any changes in OPG projections to Gross Revenue Charge and property tax payments in lieu to the Province (OEFC), which are expected to be relatively small.~~

- ~~OPG's 2017 Business Plan assumes that the OEB will approve OPG's rate application with an effective date of January 1, 2017. OPG expects OEB's decision in the third quarter of 2017 and makes note that should OEB set a later effective date, OPG's Net Income is expected to decrease by $60 million per month for the 2017/18 fiscal year.~~

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**January 1, 2017**

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## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy. This Business Plan is similar to the previous 2016-18 Business Plan, which was enclosed in OPG's 2017-2021 rate application, submitted to the Ontario Energy Board (OEB) on May 27, 2016, notwithstanding the redacted portions.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan. Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments to account for the pre-tax gain on the sale of OPG headquarters.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 349 | 406* | 678 | 726 |
| Income Tax PILs | 96 | 166** | 135 | 170 |
| **Earnings Before Tax** | **445** | **572*** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | **(250)** | **(173)*** ** | **(42)** | **84** |

* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M.
** Income Tax PILs do not have OPG head office sale backed out. Further details required from OPG.
*** Budget 2016/Fiscal Plan included OPG headquarter sales in 2016-17 which was deferred to 2017-18 in the 2017 Business Plan, and impacts removed in the above table.

**Commented [j1]:** Same question as above, is this with the OPG head office figure taken out?

**Commented [SK62R1]:** Adjusted to take out the OPG head office. Note, we haven't adjusted to the PILs impacts. Will need to get details from OPG.

### Key Highlights

*Fiscal and Rate Payer Impacts*

- The Business Plan is largely unchanged in terms of commitments for Net Income. Consistent with the previous plan, the Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The rate application results in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill.

- The decision for OPG's rate application is not expected until Q3 2017, so the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016-17 fiscal year.

*Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.
    - There will be a significant financial impact if OPG needs to permanently collect pension and OPEB costs on cash basis.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*Executive Compensation Framework*

- OPG's current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50$^{th}$ percentile of market peers.
    - Note: In November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e. financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017.
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.

**Commented [j3]:** Could EFB get a handle on the actdual figures from SIFB? Not necessarily for inclusion here in the note or the Outlook.

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**Commented [j7]:** Wouldn't getting the equity close to the deemed ration lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

**Commented [SK68R7]:** The OEB assigns the rates based on deemed capital structure, not actual capital structure. As a result, if OPG has higher equity (than deemed) and lower debt levels (than deemed), the return on equity isn't adjusted for this higher level. Furthermore, equity is compensated at a higher rate than debt, and

**Commented [j9]:** Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [SK610R9]:** The dividend would be provided to the province. The province would have the option to direct cash inflow to lower electricity prices.

**Commented [j11]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

**Commented [SK612R11]:** OPG implies it would drive greater discipline within the company.

**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations.
  - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.
- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.
- Risks from reporting OPG on an IFRS basis. OPG planning and financials are on a U.S. GAAP basis.

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**January 1, 2017**

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### Key Highlights

*Fiscal and Rate Payer Impacts*

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     - While this would likely achieve greater shareholder value, it is not clear how this would enable OPG to provide electricity rate benefits. [NTD: Let me know if you agree with this comment.]
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**Commented [j8]:** Wouldn't getting the equity close to the deemed ration lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

**Commented [SK69R8]:** The OEB assigns the rates based on deemed capital structure, not actual capital structure. As a result, if OPG has higher equity (than deemed) and lower debt levels (than deemed), the return on equity isn't adjusted for this higher level. Furthermore, equity is compensated at a higher rate than debt, and

**Commented [j10R8]:** I know that but why would that provide lower rates?

**Commented [j11]:** Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [SK612R11]:** The dividend would be provided to the province. The province would have the option to direct cash inflow to lower electricity prices.

**Commented [j13]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

**Commented [SK614R13]:** OPG implies it would drive greater discipline within the company.

**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations.
  - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.
- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.
- Risks from reporting OPG on an IFRS basis. OPG planning and financials are on a U.S. GAAP basis.

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**January 1, 2017**

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy. This Business Plan is similar to the previous 2016-18 Business Plan, which was enclosed in OPG's 2017-2021 rate application, submitted to the Ontario Energy Board (OEB) on May 27, 2016, notwithstanding the redacted portions.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments for fiscal planning purposes to remove for this table~~account for~~ the projected pre-tax gain on the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

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* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.
** Income Tax PILs do not have OPG head office sale backed out. Further details required from OPG.
*** Budget 2016/Fiscal Plan included OPG headquarter sales in 2016-17 which was deferred to 2017-18 in the 2017 Business Plan, and impacts removed in the above table.

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**Key Highlights**

*Fiscal and Rate Payer Impacts*

- The 2017-19 Business Plan is largely unchanged from the 2016-18 one in terms of commitments for Net Income. Consistent with the previous plan, the 2017-19 Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The OPG business plan reflects its rate application, which includes OPG rate increases of about~~...~~ 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated ~~is expected~~ to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about ~~xx~~50% of a typical bill, and OPG generation accounts for about yy% of total commodity costs.)
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
    - In the 2017-19 Business Plan, new regulated rates are effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month.
    - The b~~B~~usiness p~~P~~lan does not assume retroactive application for the rates, but does have the recognition of regulatory assets for the portion of the nuclear revenue requirement deferred for future recovery under nuclear rate smoothing starting in 2017.

~~*Accounting Treatments and Reporting Standards*~~

- ~~As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.~~
    - ~~There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis.~~
- ~~Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.~~

*Executive Compensation Framework*

- OPG reports that it~~'~~s current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50th percentile of market peers.
    - *CEFD Staff Comments*: On November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that



**Commented [RK1]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has OPG asked for an effective date for its new rates, and, if so, has the OEB agreed?

Is the effective date a risk to the projections?

Does OPG`s BP assume retroactive application so 16-17 includes an accrued amount for new rates to approved in 2017:Q3?

**Commented [AP2]:** BP assumes effective date in application is January 1 , 2017. It seems that OPG has not yet asked for rates to be retroactive, but they will likely do that during the first hearings (will be considered a preliminary matter) similar to what Hydro One did during the November 24, 2016 hearing for EB-2016-0160 (got deferral account approved for rates as of January 1, 2017 due to proceedings surpassing that date).

**Commented [AP3]:** BP states it is within OEB's authority to set a later effective date, which would negatively impact OPG's monthly income by ~$50M to $60M per month for the 2017/2018.

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require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
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- OPG presented 4 proposals in the Business Plan to provide greater sharedholer value and keeping electricity prices low. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
    - Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
        - *CEFD Staff Comments:* OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Therefore, OPG is referring to a higher measured percentage rate of return being higher, not higher net income. For the same net income, with lower equity, the ROE percentage would be higher. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
        - ~~*CEFD Staff Comments:* While this would likely achieve greater shareholder value, it is not clear how this would enable OPG to provide electricity rate benefits~~.
    - Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
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- Staff comment: Dividends are not revenues to the Province. OPGès net income is. Using the dividend cash for rate mitigation would have a dollar-for-dollar fiscal impact upfront, plus an IOD impact.

  - Use OPG public debt to reduce Provincial debt through public financing strategy.
    - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieved and drive a level of discipline and commercial orientation within the Company.
      - Staff comment: To-date, the government has not permitted OPG to borrow in public capital markets for general corporate purposes. OPG borrowing on its own would likely have a negative foscal impact as its cost of borrowing is expected to be higher than the Provincee's.

**Key Risks**

*Risk: Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs in regulated rates on a cash basis, with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation and OEB decision.
  - There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis with no deferral account recovery.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*OEB's decision on OPG's 2016 rate application*

- Could have potential impact on OPG's rate-regulated operations.
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*Other Risks*

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
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**Commented [RK4]:** We should elaborate on this.

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- IFRS 14, the interim standard for rate regulated accounting effective January 1, 2016, allows entities adopting IFRS to avoid major changes in accounting policy until the IASB broader project to develop a reporting standard on rate-regulated activities is completed.
- Some regulatory accounts may not be recognized by the eventual IFRS principles as creating economic benefits and obligations, resulting in the loss of potential repayments through the OEB process.
- IFRS adoption may lead to the creation of new regulatory accounts, including regulatory liabilities that, if disposal is approved by the OEB, would lead to recovery payments from OPG to ratepayers.
- Principle differences for several different accounting methods between US GAAP and IFRS, including pension costs, asset retirement obligations, and fair value measurement, may significantly impact the financial statements of OPG as well as the Province on consolidation.
- The cost of switching accounting standards, including the retrospective application of IFRS principles, must also be considered.

**Corporate and Electricity Finance Division**
**January 10, 2017**

***COMMERCIALLY SENSITIVE AND CONFIDENTIAL ADVICE TO MINISTERS***

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**Commented [GH5]:** It seems to me that this is not a risk, but a risk mitigation rather, so not sure if it fits here. Suggest to remove.

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**Commented [j3]:** Fact checked? I will need to go through the BP again tomorrow.

**Commented [SK64R3]:** Yes, from TBS Bulletin/NewsRelease

https://news.ontario.ca/tbs/en/2016/11/ontario-updating-executive-compensation-framework.html

**Commented [j5]:** Could EFB get a handle on the actdual figures from SIFB? Not necessarily for inclusion here in the note or the Outlook.

**Commented [SK66R5]:** Updated in outlook. Also made this adjustment in the OPG fiscal impact table above.

**Commented [j7]:** Pickering is not to 2024? Pls. confirm and comment as to why this deviates from the earlier announcement.

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**Commented [j9]:** Wouldn't getting the equity close to the deemed ration lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

**Commented [SK610R9]:** The OEB assigns the rates based on deemed capital structure, not actual capital structure. As a result, if OPG has higher equity (than deemed) and lower debt levels (than deemed), the return on equity isn't adjusted for this higher level. Furthermore, equity is compensated at a higher rate than debt, and

**Commented [j11R9]:** I know that but why would that provide lower rates?

**Commented [SK612R9]:** Agreed it's not very clear.

**Commented [SK613]:** I think it's fine to leave in this comment. Agreed, it doesn't seem clear that OPG would be directly providing electricity rate benefits.

To hazard a guess, one way would be to achieve greater shareholder return and this would give the province additional resources for electricity rate migitation efforts.

Two, by taking on additional debt, OPG would be able to invest in new assets to generate additional returns. However, please note this relates to #2.

**Commented [j14]:** Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [SK615R14]:** The dividend would be provided to the province. The province would have the option to direct cash inflow to lower electricity prices.

**Commented [j16]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

**Commented [SK617R16]:** OPG implies it would drive greater discipline within the company.

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**January ~~16~~ 6, 2017**

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The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan. Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments to account for the pre-tax gain on the sale of OPG headquarters.

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**Commented [j1]:** *EFB:* Same question as above, is this with the OPG head office figure taken out?

**Commented [SK62R1]:** *EFB:* Adjusted to take out the OPG head office. Note, we haven't adjusted to the PILs impacts. Will need to get details from OPG.

**Commented [AP3R1]:** BP: Sale expected to close at end of Q2 in 2017.

**Commented [AP4R1]:**

### Key Highlights

*Fiscal and Rate Payer Impacts*

- The Business Plan is largely unchanged in terms of commitments for Net Income. Consistent with the previous plan, the Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The rate application is expected to result~~s~~ in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill.

- As t~~T~~he decision for OPG's rate application is not expected until Q3 2017, ~~so~~ the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016-17 fiscal year.

*Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.
    - There wou~~ll~~d be a significant financial impact if OPG ~~needs~~ is required to permanently collect pension and OPEB costs on cash basis.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*Executive Compensation Framework*

- OPG's current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50th percentile of market peers.
    - *EFB Staff Comments*~~Note~~: O~~I~~n November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e. financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017.
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.

**Commented [j5]:** *EFB:* Fact checked? I will need to go through the BP again tomorrow.

**Commented [SK66R5]:** *EFB:* Yes, from TBS Bulletin/NewsRelease

https://news.ontario.ca/tbs/en/2016/11/ontario-updating-executive-compensation-framework.html

**Commented [j7]:** *EFB:* Could EFB get a handle on the actual figures from SIFB? Not necessarily for inclusion here in the note or the Outlook.

**Commented [SK68R7]:** *EFB:* Updated in outlook. Also made this adjustment in the OPG fiscal impact table above.

**Commented [j9]:** *EFB:* Pickering is not to 2024? Pls. confirm and comment as to why this deviates from the earlier announcement.

**Commented [SK610R9]:** *EFB:* Refers to the accounting treatment (depreciation) based on the latest rate application.

**Commented [AP11R9]:** *EFB:* Yes, to Shajee's point, OPG is waiting for technical work to confirm the ability for Pickering to achieve operations to 2024 which may be reflected in the next rate application.

- Pickering B (Units 5 to 8) had there useful lives extended from September 30, 2014 to December 31, 2020 in (EB-2015-0374) which reduced the Dep/Amor expense by $8M annually starting in 2016.
- The most recent application (EB-2016-0152) states that a future application may ask for approval of the Pickering end-of-life (EOL) date to 2024, but there is no change in the current application.
- Expected that a license hearing for Pickering in 2017 will confirm that Pickering units will operate to 2022/2024 (from the BP).

- The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.

- OPG presented 4 proposals in the Business Plan to provide greater sharedholer value and keeping electricity prices low. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
  1. Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
     - *EFB Staff Comments:* OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
     - *EFB Staff Comments:* While this would likely achieve greater shareholder value, it is not clear how this would enable OPG to provide electricity rate benefits. ~~[NTD: Let me know if you agree with this comment.]~~
  2. Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
  3. OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
  4. Use OPG public debt to reduce Provincial debt through public financing strategy.
     - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.

**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations.
  - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.
- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.
- Risks from reporting OPG on an IFRS basis. OPG planning and financials are on a U.S. GAAP basis.

**Commented [j12]:** *EFB:* Wouldn't getting the equity close to the deemed ratio lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

**Commented [SK613R12]:** *EFB:* The OEB assigns the rates based on deemed capital structure, not actual capital structure. As a result, if OPG has higher equity (than deemed) and lower debt levels (than deemed), the return on equity isn't adjusted for this higher level. Furthermore, equity is compensated at a higher rate than debt, and

**Commented [j14R12]:** I know that but why would that provide lower rates?

**Commented [SK615R12]:** Agreed it's not very clear.

**Commented [SK616]:** *EFB:* I think it's fine to leave in this comment. Agreed, it doesn't seem clear that OPG would be directly providing electricity rate benefits.

To hazard a guess, one way would be to achieve greater shareholder return and this would give the province additional resources for electricity rate migitation efforts.

Two, by taking on additional debt, OPG would be able to invest in new assets to generate additional returns. However, please note this relates to #2.

**Commented [AP17R16]:** *EFB*: Shajee's last point is critical, where aligning OPG's capital structure with the deemed equity and debt weights would allow OPG to invest more in assets that generate return.
- In the most recent rate application (EB-2016-0152), the deemed debt for OPG in order to achieve the requested deemed structure is $3B in 2016 and goes over $4.5B b ...

**Commented [j18]:** *EFB:* Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [SK619R18]:** The dividend would be provided to the province. The province would have the option to direct cash inflow to lower electricity prices.

**Commented [AP20R18]:** *EFB:* This is an interesting proposition, as the dividend can be used to lower OPG's equity with the cash used to fund a governmental rebate of some sort.

**Commented [j21]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

**Commented [SK622R21]:** OPG implies it would drive greater discipline within the company.

**Commented [AP23R21]:** *EFB:* securing debt from public financing would strengthen OPG's stance as a GBE. Furthermore, OPG should be receiving market rates from the province for its debt as it is functioning as a GBE.

**Electricity Finance Branch, Corporate and Electricity Finance Division**
**January ~~1~~10, 2017**

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

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### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan.

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Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments for fiscal planning purposes to remove for this table~~account for~~ the projected pre-tax gain on the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

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    - The OPG business plan reflects its rate application, which includes OPG rate increases of about~~...~~ 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated ~~is expected~~ to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about ~~xx%~~half of a typical bill, and OPG generation accounts for about ~~yy%~~half of total commodity costs.)
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
    - In the 2017-19 Business Plan, new regulated rates are assumed to be effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month.
    - The b~~B~~usiness p~~P~~lan does not assume retroactive application for the rates, but does have the recognition of regulatory assets for the portion of the nuclear revenue requirement deferred for future recovery under nuclear rate smoothing starting in 2017.

~~*Accounting Treatments and Reporting Standards*~~

- ~~As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.~~
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*Executive Compensation Framework*

- OPG reports that it~~'~~s current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50th percentile of market peers.
    - *CEFD Staff Comments*: On November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can



**Commented [RK1]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has OPG asked for an effective date for its new rates, and, if so, has the OEB agreed?

Is the effective date a risk to the projections?

Does OPG`s BP assume retroactive application so 16-17 includes an accrued amount for new rates to approved in 2017:Q3?

**Commented [AP2]:** BP assumes effective date in application is January 1 , 2017. It seems that OPG has not yet asked for interim rates, but they will likely do that during the first hearings (will be considered a preliminary matter) similar to what Hydro One did during the November 24, 2016 hearing for EB-2016-0160 (got interim rates as of January 1, 2017 due to proceedings surpassing that date).

**Commented [AP3]:** BP states it is within OEB's authority to set a later effective date, which would negatively impact OPG's monthly income by ~$50M to $60M per month for the 2017/2018.

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**Commented [j4]:** Is this right? The decision would authorize either the riders for the delayed implementation, no?

**Commented [AP5R4]:** These concepts are taken directly from the business plan. OPG is currently asking for two rate riders that have to do with existing deferral and variance balances at the end of 2015 (see the OPG rate rider note I started). So, the rate riders to come into effect in 2017 are for deferral and variance accounds from 2015. Thus, let's say the delay in the rate impact kept $150M off the table, then this amount would likely be recovered from a future rate rider down the road (through deferral account from date of interm rates). Furthermore, it is not in the practice of the OEB to retroactively adjust rates back to the start of a utility's rate year.

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benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e., financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017. [The actual borrowing under the facility was $0.1 billion in 2016.]
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
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- OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
  - Staff comment: Dividends are not revenues to the Province. OPGès net income is. Using the dividend cash for rate mitigation would have a dollar-for-dollar fiscal impact upfront, plus an IOD impact.
- Use OPG public debt to reduce Provincial debt through public financing strategy.
  - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.
    - Staff comment: To-date, the government has not permitted OPG to borrow in public capital markets for general corporate purposes. OPG borrowing on its own would likely have a negative fiscal impact as its cost of borrowing is expected to be higher than the Provincee's.

**Key Risks**

*Risk: Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs in regulated rates on a cash basis, with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation and OEB decision.
  - There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis with no deferral account recovery.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*OEB's decision on OPG's 2016 rate application*

- Could have potential impact on OPG's rate-regulated operations.
  - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.

*Other Risks*

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
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***COMMERCIALLY SENSITIVE AND CONFIDENTIAL ADVICE TO MINISTERS***

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- ~~Additional r~~Risks from reporting OPG on an IFRS basis, ~~as~~ OPG planning and financials are still on a U.S. GAAP basis.
  - IFRS 14, the interim standard for rate regulated accounting effective January 1, 2016, allows entities adopting IFRS to avoid major changes in accounting policy until the IASB broader project to develop a reporting standard on rate-regulated activities is completed.
  - Some regulatory accounts may not be recognized by the eventual IFRS principles as creating economic benefits and obligations.
  - Principle differences for several different accounting methods between US GAAP and IFRS, including pension costs, asset retirement obligations, and fair value measurement, may significantly impact the financial statements of OPG as well as the Province on consolidation.
  - The cost of switiching accounting standards, including the retrospective application of IFRS principles, must also be considered.

**Corporate and Electricity Finance Division**
**January 10, 2017**



**Commented [RK6]:** We should elaborate on this.

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**Commented [GH7]:** It seems to me that this is not a risk, but a risk mitigation rather, so not sure if it fits here. Suggest to remove.

**Commented [j8]:** Deleted this part as as far as I know OEB is not opposed to the use of USGAAP. My understanding is that the adverse impact is upon consolidation to the Province's accounts.

**Commented [AP9R8]:** Ok, let's discuss as to me since province uses modified equity method (if OPG remains a GBE), then what method OPG uses directly relates to the consolidation impact. I agree that an adverse impact from consolidation is related to the GBE status of OPG. Effective January 2015, Province has to report what the effect of IRFS consolidation will have on GBE net assets and income including OPG.

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**Commented [RK1]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has OPG asked for an effective date for its new rates, and, if so, has the OEB agreed?

Is the effective date a risk to the projections?

Does OPG`s BP assume retroactive application so 16-17 includes an accrued amount for new rates to approved in 2017:Q3?

**Commented [AP2]:** BP assumes effective date in application is January 1 , 2017. It seems that OPG has not yet asked for interim rates, but they will likely do that during the first hearings (will be considered a preliminary matter) similar to what Hydro One did during the November 24, 2016 hearing for EB-2016-0160 (got interim rates as of January 1, 2017 due to proceedings surpassing that date).

**Commented [AP3]:** BP states it is within OEB's authority to set a later effective date, which would negatively impact OPG's monthly income by ~$50M to $60M per month for the 2017/2018.

**Commented [j4]:** Is this right? The decision would authorize either the riders for the delayed implementation, no?

**Commented [AP5R4]:** These concepts are taken directly from the business plan. OPG is currently asking for two rate riders that have to do with existing deferral and variance balances at the end of 2015 (see the OPG rate rider note I started). So, the rate riders to come into effect in 2017 are for deferral and variance accounds from 2015. Thus, let's say the delay in the rate impact kept $150M off the table, then this amount would likely be recovered from a future rate rider down the road (through deferral account from date of interm rates). Furthermore, it is not in the practice of the OEB to retroactively adjust rates back to the start of a utility's rate year.

require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e., financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017. [The actual borrowing under the facility was $0.1 billion in 2016.]
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with the first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.
        - The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.

- OPG presented 4 proposals in the Business Plan to provide greater sharedholer value and keeping electricity prices low. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
    - Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
        - *CEFD Staff Comments:* OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Therefore, OPG is referring to a higher measured percentage rate of return being higher, not higher net income. For the same net income, with lower equity, the ROE percentage would be higher. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
        - ~~*CEFD Staff Comments:* While this would likely achieve greater shareholder value, it is not clear how this would enable OPG to provide electricity rate benefits~~.
    - Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.

- OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
  - *CEFD Staff comment:* Dividends are not revenues to the Province. OPG~~e~~'s net income is. Using the dividend cash for rate mitigation would have a dollar-for-dollar fiscal impact upfront, plus an IOD impact.
- Use OPG public debt to reduce Provincial debt through public financing strategy.
  - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieved and drive a level of discipline and commercial orientation within the Company.
    - *CEFD Staff comment:* To-date, the government has not permitted OPG to borrow in public capital markets for general corporate purposes. OPG borrowing on its own would likely have a negative fi~~e~~scal impact as its cost of borrowing is expected to be higher than the Provincee's.

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**Key Risks**

*Risk: Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs in regulated rates on a cash basis, with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation and OEB decision.
  - There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis with no deferral account recovery.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*OEB's decision on OPG's 2016 rate application*

- ~~c~~Could have potential impact on OPG's rate-regulated operations.
  - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.

*Other Risks*

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.

- ~~Additional r~~RRisks from reporting OPG on an IFRS basis, as~~.~~ OPG planning and financials are still on a U.S. GAAP basis.
  - IFRS 14, the interim standard for rate regulated accounting effective January 1, 2016, allows entities adopting IFRS to avoid major changes in accounting policy until the IASB broader project to develop a reporting standard on rate-regulated activities is completed.
  - Some regulatory accounts may not be recognized by the eventual IFRS principles as creating economic benefits and obligations.
  - Principle differences for several different accounting methods between US GAAP and IFRS, including pension costs, asset retirement obligations, and fair value measurement, may significantly impact the financial statements of OPG as well as the Province on consolidation.
  - The cost of switiching accounting standards, including the retrospective application of IFRS principles, must also be considered.

**Corporate and Electricity Finance Division**
**January ~~10~~16, 2017**



**Commented [RK6]:** We should elaborate on this.

**Commented [GH7]:** It seems to me that this is not a risk, but a risk mitigation rather, so not sure if it fits here. Suggest to remove.

**Commented [j8]:** Deleted this part as as far as I know OEB is not opposed to the use of USGAAP. My understanding is that the adverse impact is upon consolidation to the Province's accounts.

**Commented [AP9R8]:** Ok, let's discuss as to me since province uses modified equity method (if OPG remains a GBE), then what method OPG uses directly relates to the consolidation impact. I agree that an adverse impact from consolidation is related to the GBE status of OPG. Effective January 2015, Province has to report what the effect of IRFS consolidation will have on GBE net assets and income including OPG.

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy. This Business Plan is similar to the previous 2016-18 Business Plan, which was enclosed in OPG's 2017-2021 rate application, submitted to the Ontario Energy Board (OEB) on May 27, 2016, notwithstanding the redacted portions.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan. Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments to account for the pre-tax gain on the sale of OPG headquarters.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

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| **EBT Variance to Fiscal Plan** | **(250)** | **(173)***** | **(42)** | **84** |

* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.

** Income Tax PILs do not have OPG head office sale backed out. Further details required from OPG.

*** Budget 2016/Fiscal Plan included OPG headquarter sales in 2016-17 which was deferred to 2017-18 in the 2017 Business Plan, and impacts removed in the above table.

### Key Highlights

*Fiscal and Rate Payer Impacts*

- The Business Plan is largely unchanged in terms of commitments for Net Income. Consistent with the previous plan, the Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The rate application is expected to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill.

- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016-17 fiscal year.

*Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.
    - There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis.
- Adoption of International Financial Reporting Standards (IFRS) would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan. OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.

*Executive Compensation Framework*

- OPG's current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50$^{th}$ percentile of market peers.
    - *CEFD Staff Comments*: On November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

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**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations.
    - Furthermore a delay in the effective date of the newly regulated rates might reduce OPG's net income by approximately $50 million to $60 million per month, for the 2017-18 fiscal year. The Business Plan assumes an effective date of the newly regulated rates on January 1, 2017.
- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.
- Risks from reporting OPG on an IFRS basis. OPG planning and financials are on a U.S. GAAP basis.

**Corporate and Electricity Finance Division**
**January 10, 2017**

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

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### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the Business Plan have had preliminary adjustments for fiscal planning purposes to remove for this table~~account for~~ the projected pre-tax gain on the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

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~~*Accounting Treatments and Reporting Standards*~~

- ~~As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation.~~
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**Corporate and Electricity Finance Division**
**January 10, 2017**



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    - In the 2017-19 Business Plan, new regulated rates are effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month.
    - The BP does not assume retroactive application for the rates, but does have the recognition of regulatory assets for the portion of the nuclear revenue requirement deferred for future recovery under nuclear rate smoothing starting in 2017.

~~*Accounting Treatments and Reporting Standards*~~

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- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
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- Some regulatory accounts may not be recognized by the eventual IFRS principles as creating economic benefits and obligations, resulting in the loss of potential repayments through the OEB process.
- IFRS adoption may lead to the creation of new regulatory accounts, including regulatory liabilities that, if disposal is approved by the OEB, would lead to recovery payments from OPG to ratepayers.
- Principle differences for several different accounting methods between US GAAP and IFRS, including pension costs, asset retirement obligations, and fair value measurement, may significantly impact the financial statements of OPG as well as the Province on consolidation.
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**Corporate and Electricity Finance Division**
**January 10, 2017**

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## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

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The following tables provides a comparision between Budget 2016 and the latest financial projectsions submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the 2017-19 Business Plan have had preliminary adjustments for fiscal planning purposes to remove for this table~~account for~~ the projected pre-tax gain on the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

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* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.
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**Key Highlights**

*Fiscal and Rate Payer Impacts*

- The 2017-19 Business Plan is largely unchanged from the 2016-18 one in terms of commitments for Net Income. Consistent with the previous plan, the 2017-19 Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The OPG business plan reflects its rate application, which includes OPG rate increases of about~~...~~ 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated ~~is expected~~ to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about ~~xx%~~half of a typical bill, and OPG generation accounts for about ~~yy%~~half of total commodity costs.)
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
    - In the 2017-19 Business Plan, new regulated rates are assumed to be effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month.
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**Corporate and Electricity Finance Division**
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**Corporate and Electricity Finance Division**
**January 10, 2017**



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## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

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Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The 2017-18 forecasts in the 2017-19 Business Plan have had preliminary adjustments for fiscal planning purposes to remove for this table~~account for~~ the projected pre-tax gain on the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

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**Key Highlights**

*Fiscal and Rate Payer Impacts*

- The 2017-19 Business Plan is largely unchanged from the 2016-18 one in terms of commitments for Net Income. Consistent with the previous plan, the 2017-19 Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021.
    - The OPG business plan reflects its rate application, which includes OPG rate increases of about~~...~~ 1.5% per year for hydroelectric base rate starting in 2017 and 11% per year increase for nuclear generation consistent with its rate smoothing proposal, which are estimated ~~is expected~~ to result in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill. (Commodity costs represent about ~~xx%~~half of a typical bill, and OPG generation accounts for about ~~yy%~~half of total commodity costs.)
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
    - In the 2017-19 Business Plan, new regulated rates are assumed to be effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month.
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~~*Accounting Treatments and Reporting Standards*~~

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*Executive Compensation Framework*

- OPG reports that it~~'~~s current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50th percentile of market peers.
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*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
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**Key Risks**

*Risk: Accounting Treatments and Reporting Standards*

- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs in regulated rates on a cash basis, with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation and OEB decision.
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*OEB's decision on OPG's 2016 rate application*

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*Other Risks*

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
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**Corporate and Electricity Finance Division**
**January ~~10~~16, 2017**

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The key drivers of the variances include the following:

- [Insert bullets to explain variances in each year.]

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**OTHER BUSINESS PLAN HIGHLIGHTS**

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- The delay in OPG's previously planned rate application in 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017 has an adverse impact of about $100 million.
- In its rate decision for OPG's 2014 and 2015 rates, the Ontario Energy Board's (OEB) decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates has put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.
- There is a risk that a portion of Darlington Refurbishment Project's assets coming into service (about $700-800 million) may be disallowed. A portion of the expenditures on the heavy water (D2O) storage facility (which totalled about $300 million) may be at greater risk of being disallowed.

**Commented [SK71]:** From prior Business Plan Briefing Note.

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    - E.g., for each $1 per megawatt-hour (MWh) reduction in OPG's nuclear rate, OPG's projected financial results would decrease by $xx million, and for each $1 per MWh reduction in the regulated hydroelectric rate, OPG's resuls would be $xx million lower.
- As the decision for OPG's rate application is not expected until Q3 2017, the outcome of the new rate application will not be known in time to be reflected in OPG's projected results that will be included in the 2017 Document's fiscal plan, nor consolidated with the Province's 2016-17 fiscal year results.
- In the 2017-19 Business Plan, new regulated rates are assumed to be effective January 1, 2017.
    - A delay in this effective date is expected to result in an approximately $50 million to $60 million reduction in net income per month, which could be reflected, cumulativel, in 2017-18, when the OEB rate decision is expected to occur. [TBC]
    - The business plan does not assume retroactive application for the rates, but does have the recognition of regulatory assets for the portion of the nuclear revenue requirement deferred for future recovery under nuclear rate smoothing starting in 2017.

**Commented [RK2]:** Can we say that OPG has asked for the rates to be retroactive to January 2017 (through deferral accounts to be recovered going forward?) Has OPG asked for an effective date for its new rates, and, if so, has the OEB agreed?

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***Accounting Treatment and Reporting Standards***

- The OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs).
    - OPG currently collects pension and OPEB costs in regulated rates on a cash basis, with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation and OEB decision.
    - There would be a significant financial impact if OPG is required to permanently collect pension and OPEB costs on cash basis with no deferral account recovery.
- Adoption of International Financial Reporting Standards (IFRS) for OPG results, and as consolidated into Public Accounts, would result in a significant increase in income volatility and would require a reassessment of OPG's fiscal commitments in the Business Plan.
    - OPG's current exemption with the Ontario Securities Commission that allows it to report on a basis other than IFRS expires at the end of 2018.
    - OPG planning and financials are still on a U.S. GAAP basis.
    - IFRS 14, the interim standard for rate regulated accounting effective January 1, 2016, allows entities adopting IFRS to avoid major changes in accounting policy until the IASB broader project to develop a reporting standard on rate-regulated activities is completed.
    - Some regulatory accounts may not be recognized by the eventual IFRS principles as creating economic benefits and obligations.
    - Principle differences for several different accounting methods between US GAAP and IFRS, including pension costs, asset retirement obligations, and fair value measurement, may significantly impact the financial statements of OPG as well as the Province on consolidation.
    - The cost of switching accounting standards, including the retrospective application of IFRS principles, must also be considered.

*Other Risks*

- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
- Failure to maintain appropriate staff level and resources during Darlington refurbishment and Pickering operations.
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020.

**OTHER BUSINESS PLAN HIGHLIGHTS**

*Executive Compensation Framework*

- OPG reports that its current management compensation restraint initiatives have made attracting and retaining talent a challenge. OPG has requested approval for a proposed Executive Compensation Framework (ECF), generally targeted at the 50$^{th}$ percentile of market peers.
    - *CEFD Staff Comments*: On November 22, 2016, the Province amended the Executive Compensation Framework regulation to ensure broader public sector organizations can benchmark compensation for senior nuclear technical experts against other jobs that require the same unique skills and experience. This amendment will ensure Ontario is able to attract and retain the highly specialized executive talent necessary to safely operate its

large nuclear facilities and generate Ontario's single largest source of emissions-free electricity.

*Other Highlights*

- The sale of OPG's head office is on track for 2017-18 fiscal year.
- OPG's headcount continues to decline, as reported in the monthly update. Note that the Darlington Refurbishment headcount is not considered part of ongoing operations.
- Total long-term debt for general corporate (i.e., financing through OEFC) is forecast to increase by $1.6 billion, from $0.2 billion in 2016 to $1.8 billion in 2017. [The actual borrowing under the facility was $0.1 billion in 2016.]
- The Business Plan includes approved budget and schedule for the Darlington Refurbishment Project, with the first unit beginning in October 2016, and assumes it returns to service in February 2020.
- The plan assumes all six operating Pickering units operate until 2022, with four of these units operating until 2024. The plan includes additional costs and outage days to achieve Pickering operations beyond 2020, in line with the business case approved by the Board.
    - The Business plan reflects currently approved station service lives, *for accounting purposes*, for the Pickering GS to the end of 2020 and for the Darlington GS to 2052.
        - The Pickering service life will be reassessed upon technical work confirming ability to achieve operations beyond 2020.

- OPG presented 4 proposals in the Business Plan to provide greater sharedholer value and keeping electricity prices low. Note, while these proposals are presented in the BP, they are **not** assumed in the Business Plan.
    - Align OPG's Capital Structure with the OEB's deemed capital structure to improve OPG's actual return on equity.
        - *CEFD Staff Comments:* OPG's revenue requirements are based on deemed capital structure rather than actual capital structure. As a result, OPG's shareholder (the Province) is not compensated for the increased equity capital put at risk. Therefore, OPG is referring to a higher measured percentage rate of return being higher, not higher net income. For the same net income, with lower equity, the ROE percentage would be higher. Furthermore, should the level of debt be increased to achieve the deemed capital structure, the weighted cost of capital and revenue requirement would reflect the increased debt service costs.
        - .
    - Invest in OPG's assets to maintain OPG's critical size, so it can continue to mitigate prices for customers, about 30% to 40% below other generators.
    - OPG to establish a dividend program tied to key business outcomes, which could return about $2.4 billion to the shareholder. The Province could use this dividend to fund government priorities including lowering the price of electricity should it so choose.
        - *CEFD Staff comment:* Dividends are not revenues to the Province. OPG's net income is. Using the dividend cash for rate mitigation would have a dollar-for-dollar fiscal impact upfront, plus an IOD impact.

- Use OPG public debt to reduce Provincial debt through public financing strategy.
    - Maturing debt and future additional debt could be financed through the public debt markets. In addition, the OEB's deemed capital structure can be achieived and drive a level of discipline and commercial orientation within the Company.
        - *CEFD Staff comment:* To-date, the government has not permitted OPG to borrow in public capital markets for general corporate purposes. OPG borrowing on its own would likely have a negative fiscal impact as its cost of borrowing is expected to be higher than the Provincee's.

**Corporate and Electricity Finance Division**
**January ~~16~~18, 2017**

## ONTARIO POWER GENERATION – 2017-19 BUSINESS PLAN

On November 28, 2016, OPG provided its 2017-19 Business Plan ("Business Plan") to the Minister of Energy.

### Fiscal Impacts

The following tables provides a comparision between Budget 2016 and the latest financial projections submitted by OPG in its 2017-19 Business Plan.

Note that OPG contributions to the fiscal plan in Budget 2016 was primarily based on OPG's 2015 business plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.

Earnings Before Tax is now forecasted to be lower by $250 million in 2016-17, lower in 2017-18 by $173 million, lower in 2018-19 by $42 million and higher in 2019-20 by $84 million.

The key drivers of the variances include the following:

- As noted above, the current fiscal plan estimates include estimates at the time of OPG's 2015 business plan. On May 27, 2016, OPG submitted its rate application for 2017-2021 payment amounts for its prescribed facilities to the Ontario Energy Board (OEB). The current estimates of OPG's contributions to the fiscal plan are based on OPG's 2017-19 business plan reflecting its current expectations, including OPG's current expectations on key regulatory risks.
- ~~[Insert bullets to explain variances in each year.]Budget 2016/Fiscal Plan included OPG headquarter sales in 2016-17 which was deferred to 2017-18 in the 2017 Business Plan, with impacts excluded in 2017-18 as the expected gain on sale is reflected as an asset optimization component captures in the sales and rental line under Non-Tax Revenue.~~

~~The delay in OPG's previously planned rate application in 2015 for rates starting in 2016 to the revised plan to submit in Spring 2016 for rates effective January 1, 2017 has an adverse impact of about $100 million.~~

  - In its rate decision for OPG's 2014 and 2015 rates, ~~the Ontario Energy Board's (~~OEB's~~)~~ decision to allow OPG to recover only its cash requirements for pension and other post-employment benefits (OPEB) in 2014 and 2015 rates has put at risk about $450-500 million for the difference in OPG's accrued costs that it recognises on its audited financial statements versus the cash costs. OPG has been recording this difference in a regulatory deferral account, but it is not certain if the OEB will approve recovery of that amount.
  - There is a risk that a portion of Darlington Refurbishment Project's assets coming into service (about $700-800 million) may be disallowed. A portion of the expenditures on the heavy water (D2O) storage facility (which totalled about $300 million) may be at greater risk of being disallowed.

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**Commented [SK71]:** From prior Business Plan Briefing Note.

As mentioned above ~~Note that~~ the 2017-18 forecasts in the 2017-19 Business Plan have had preliminary staff adjustments for fiscal planning purposes to remove for this table the projected pre-tax gain of $296

million included in OPG's business plan from the sale of OPG headquarters properties to avoid double-counting as those revenue amounts are included under asset optimisation.

Note also that the following is on OPG's U.S. GAAP basis of accounting, and does not show consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 349 | 406* | 678 | 726 |
| Income Tax PILs | 96 | 166** | 135 | 170 |
| **Earnings Before Tax** | **445** | **572*** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | **(250)** | **(173)***** | **(42)** | **84** |

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### Key Highlights

- The Business Plan is largely unchanged in terms of commitments for Net Income. Consistent with the previous plan, the Business Plan projects net income growing to about $730 million in 2019 and $1 billion in 2021. The rate application results in average increases of about 0.7% or $1.05 per month annually on a typical residential customer's monthly bill.
- The decision for OPG's rate application is not expected until Q3 2017, so the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016-17 fiscal year.
- As the OEB has been holding a generic consultation on the treatment of rate-regulated utilities' pensions and other post-employment benefits (OPEBs), OPG currently collects pension and OPEB costs from customers on a cash basis with the difference between cash and accrual recorded in a deferral account until the conclusion of the consultation. There will be a significant financial impact if OPG needs to permanently collect pension and OPEB costs on cash basis.
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**Key Risks**

- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations. The outcome of rate application will might have negative impact on OPG's net income, approximately $60 million per month, for the 2017-18 fiscal year, if OEB postponed the effective date of OPG's proposed new regulated rates. The Business Plan assumes the new regulated rates at the beginning of 2017.
- Failure to keep the Darlington refurbishment project on track in terms of cost, schedule, and other associated activities.
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**Commented [j1]:** Let's minimize this as it was sent as a preliminary BP.

### Key Highlights

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    - Align OPG's Capital Structure with the OEB to improve OPG's actual return on equity.

**Commented [j2]:** Could EFB get a handle on the actdual figures from SIFB? Not necessarily for inclusion here in the note or the Outlook.

**Commented [j3]:** Pickering is not to 2024? Pls. confirm and comment as to why this deviates from the earlier announcement.

**Commented [j4]:** Wouldn't getting the equity close to the deemed ration lead to lower actual equity? Why would raising the actual levels of debt and lowering equity necessarily lead to lower rates? A brief explanation would be helpful.

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- Use OPG public debt to reduce Provincial debt.

**Commented [j5]:** Why would a dividend program be tied to rate mitigation? If true, pls. provide a brief explanation.

**Commented [j6]:** This would be towards a detriment to the electricity price mitigation as OPG would face higher rates.

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- OEB's decision on OPG's 2016 rate application could have potential impact on OPG's rate-regulated operations. The outcome of rate application will might have negative impact on OPG's net income, approximately $60 million per month, for the 2017-18 fiscal year, if OEB postponed the effective date of OPG's proposed new regulated rates. The Business Plan assumes the new regulated rates at the beginning of 2017.
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# OPG 2017-19 Business Plan Questions

**Q1: What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast?**

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|---|---|---|---|
| Net Income After Tax | 471 | 586 | 673 |
| Income Taxes | 224 | 159 | 182 |
| **Earnings Before Tax** | **695** | **745** | **855** |

| OPG 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 302 | 694 | 686 |
| Income Taxes | 104 | 245 | 155 |
| **Earnings Before Tax** | **406** | **939** | **841** |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | 349 | 702 | 678 | 726 |
| **Income Tax PILs** | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **445** | **868** | **813** | **896** |

**Q2: Can you provide the breakdown of GRC, Proxy Property Tax, and Ontario Capital Tax for fiscal years 2016-2020 based on OPG's 2017-19 business plan?**

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **GRC: Payable to OEFC** | | | | |
| **GRC: Payable to NPC** | | | | |
| **Property Tax Payable to OEFC** | 15 | 18 | 19 | 19 |
| **Total** | **336** | **350** | **363** | **362** |
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| **Current Income Tax Payable** | | | | |
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| **Income Taxes Payable to Ratepayers** | | | | |
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**Q3: In addition, could you provide a financial summary of the OPG head office sale (i.e. pre-tax gain of $296)? What is the PIL expense without this headquarter sales gain?**

- **Is there a PILs element related to the headquarter sale in the $166M PIL number provided? [Essentially, we would like OPG's insight on the allocation of $296M to PILs vs. Net Income].**
- **Could we also confirm that $296M is the amount built into the 2017-19 BP forecast for 2017-18?**
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## General OPG Business Plan Questions

**Q4: Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "OEB's decision on OPG's rate application is expected during the third quarter of 2017." Is it your current outlook that OEB's decision would still be retroactive to January 1, 2017?**

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**Q7: In the past, OPG had a provision of approximately $200 million in their forecast model that was provided. Could you confirm if this provision is included in the current BP numbers? Similarly in the past, could you also provide the forecast model?**

# OPG 2017-19 Business Plan Questions

**Q1: What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast?**

| OPG 2015-17 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax | 471 | 586 | 673 |
| Income Taxes | 224 | 159 | 182 |
| **Earnings Before Tax** | **695** | **745** | **855** |

| OPG 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
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## OPG Business Plan in general

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~~c)~~ **Q7: In the past, OPG had a provision of approximately $200 million in their forecast models. Could you confirm if this provision is not included in the BP numbers?**

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**Q7: In the past, OPG had a provision of approximately $200 million in their forecast model that was provided. Could you confirm if this provision is included in the current BP numbers? Similarly in the past, could you also provide the forecast model?**

**Q8: Can you provide a more detailed financing and liquidity outlook, specifically the operating cash flow section of the cash flow statement, to explain the drivers behind the ~$1B reduction in operating cash flow in 2017, as well as changes throughout 2016-2021? This is in order to reconcile the $1.2B change in net operating cash flow for 2017 from 2016 ($2.739B in 2016 to $1.531B in 2017). The BP states this is due to lower production, a foregone rate rider, and accrual of new rates in net income; however, the movements in the financial statements (i.e., income accounts and B/S operating account movements) are significantly lower than the $1.2B amount.**

# OPG 2017-19 Business Plan Questions

1. **What are the explanation for EBT variances between 2015-17 business plan forecast, 2016-18 business plan forecast and 2017-19 business plan forecast? Note, that 2016 Budget was based on the 2015-17 business plan.**

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2. **OPG previously provided a response to a request to provide the breakdown of GRC, Proxy Property Tax for 2016-2020 based on OPG's 2017-19 business plan. OPG's response provided, i) GRC: Payable to OEFC, ii) GRC: Payable to Niagara Parks Commission and iii) Property Tax Payable to OEFC.**

   **Follow-up question: We are aware of the legislative amendment in 2006 which, effective Jan. 1, 2009, redirected to the OEFC the GRC-Property tax previously payable to MoF. Has there been an amendment to redirect the GRC: water rental charge to the OEFC from Finance?**

**General OPG 2016-18 Business Plan Questions**

3. **On Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "OEB's decision on OPG's rate application is expected during the third quarter of 2017." Does OPG's current outlook assume that OEB's decision would still be retroactive to January 1, 2017?**

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   c) **OPG's Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016.**

   **Given the above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)? If so, what accounts for the lower than usual quarterly earnings?**

6. **Q8: Can you provide a more <u>detailed</u> financing and liquidity outlook<u>, specifically the operating cash flow section of the cash flow statement</u>, to explain the drivers behind the ~$1B reduction in operating cash flow in 2017, as well as changes throughout 2016-2021? This is in order to reconcile the $1.2B change in net operating cash flow for 2017 from 2016 ($2.739B in 2016 to $1.531B in 2017). The BP states this is due to lower production, a foregone rate rider, and accrual of new rates in net income; however, the movements in the financial statements (i.e., income accounts and B/S operating account movements) are significantly lower than the $1.2B amount.**

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

**Tel: 416-592-2115**
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

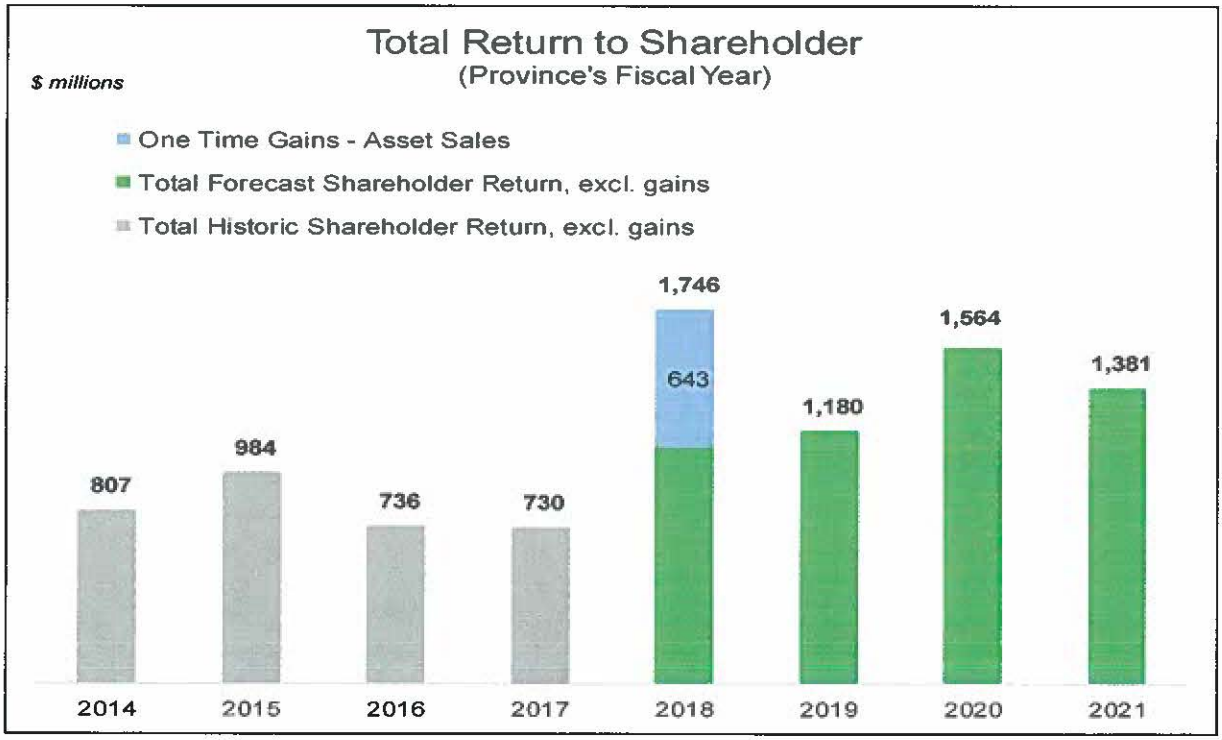
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

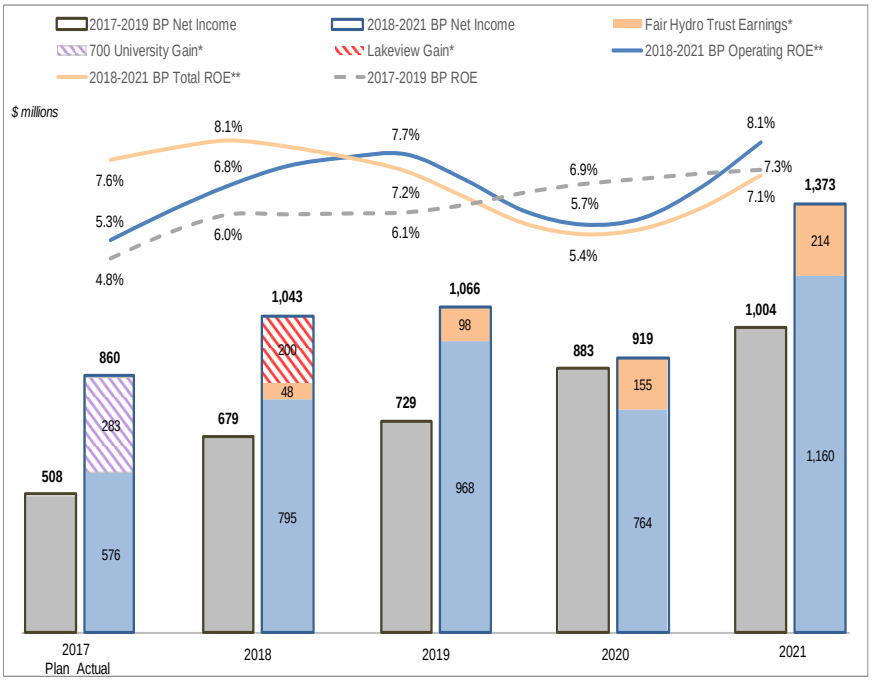
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

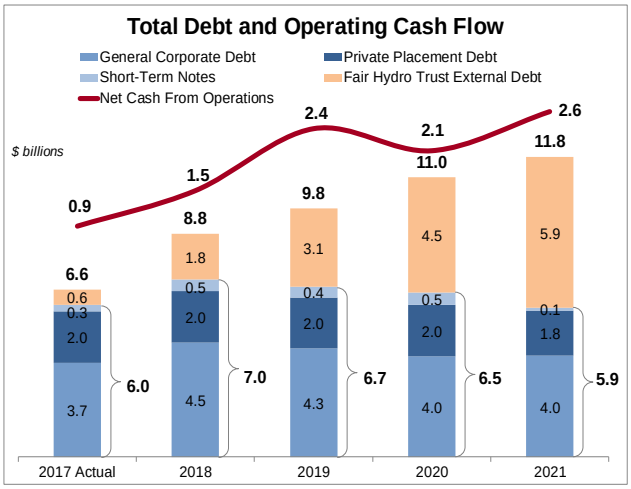
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

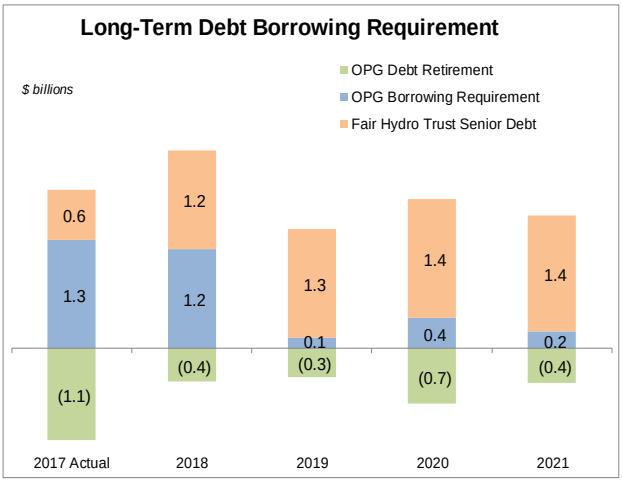
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

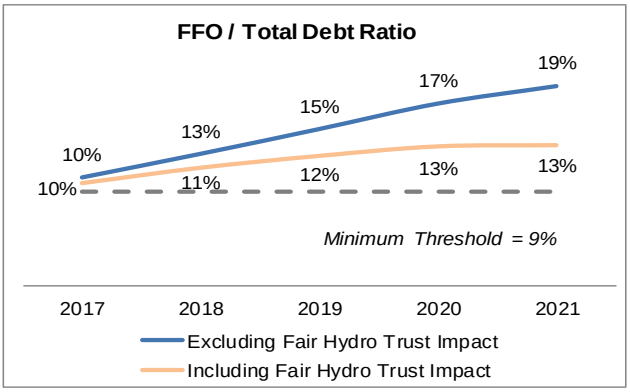


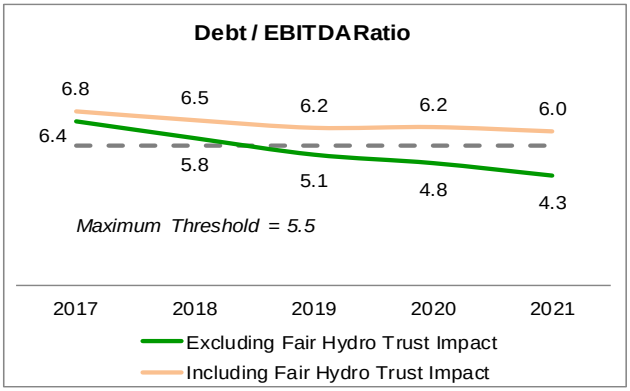

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



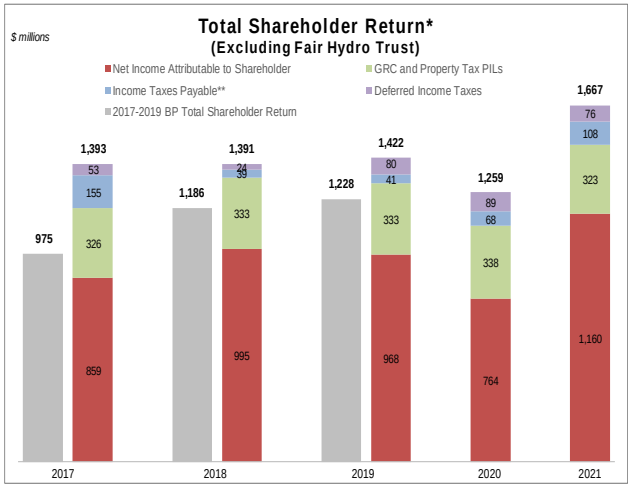

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

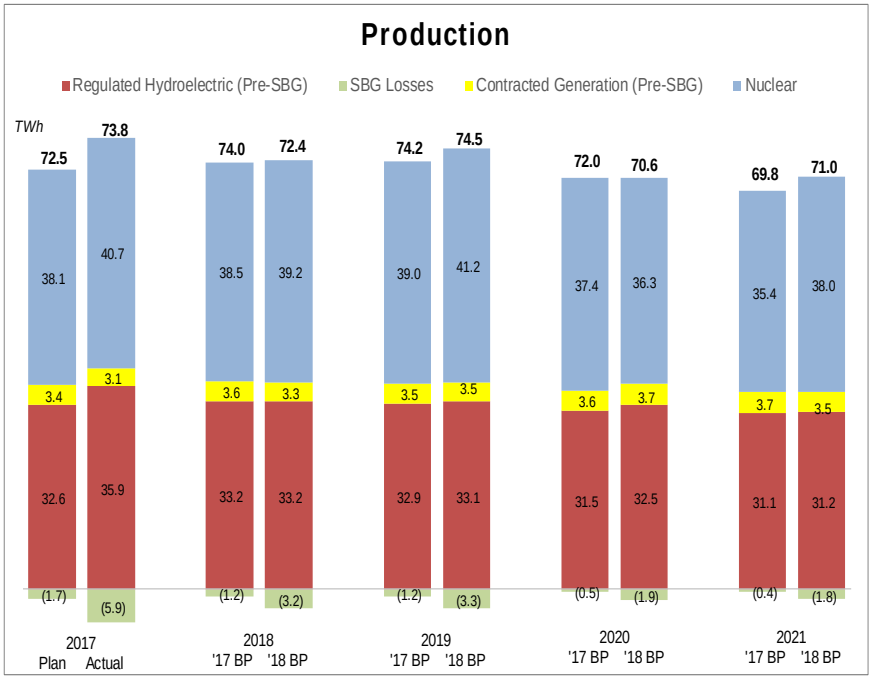
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

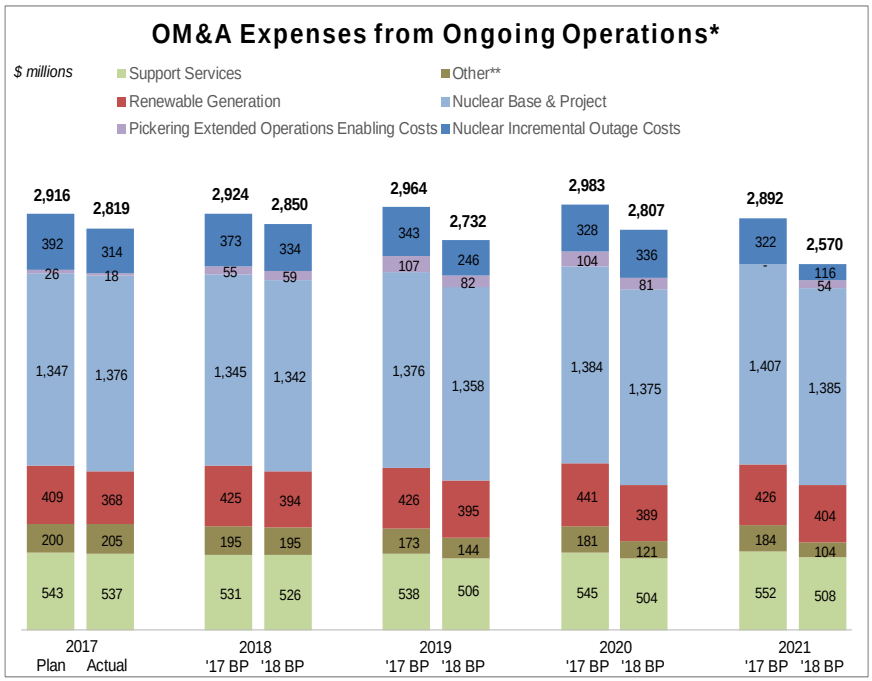
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

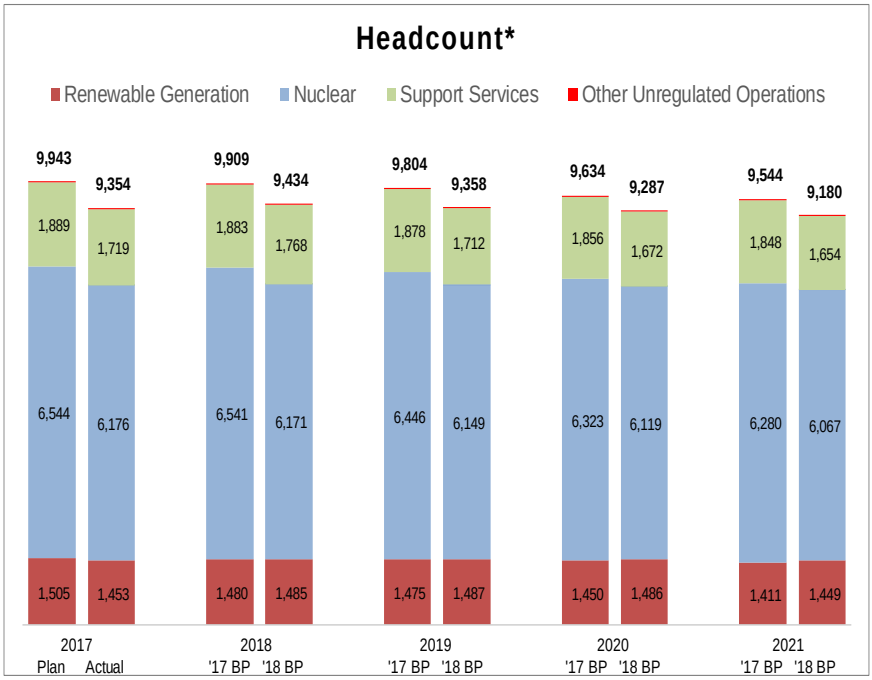
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

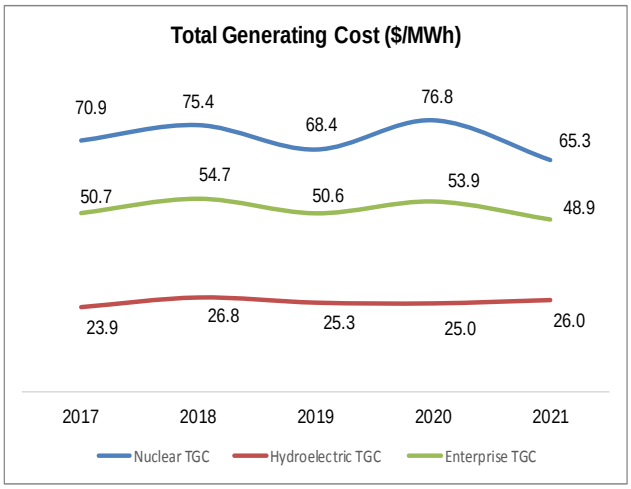
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

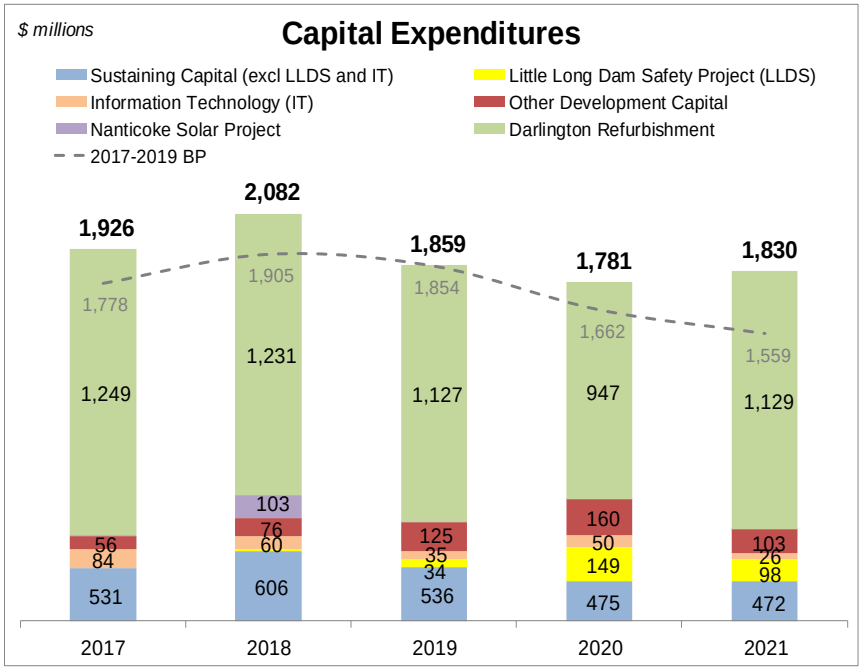
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

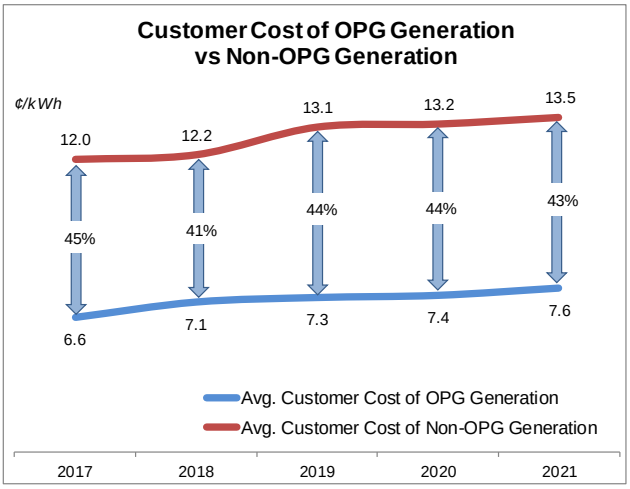
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 73 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

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February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

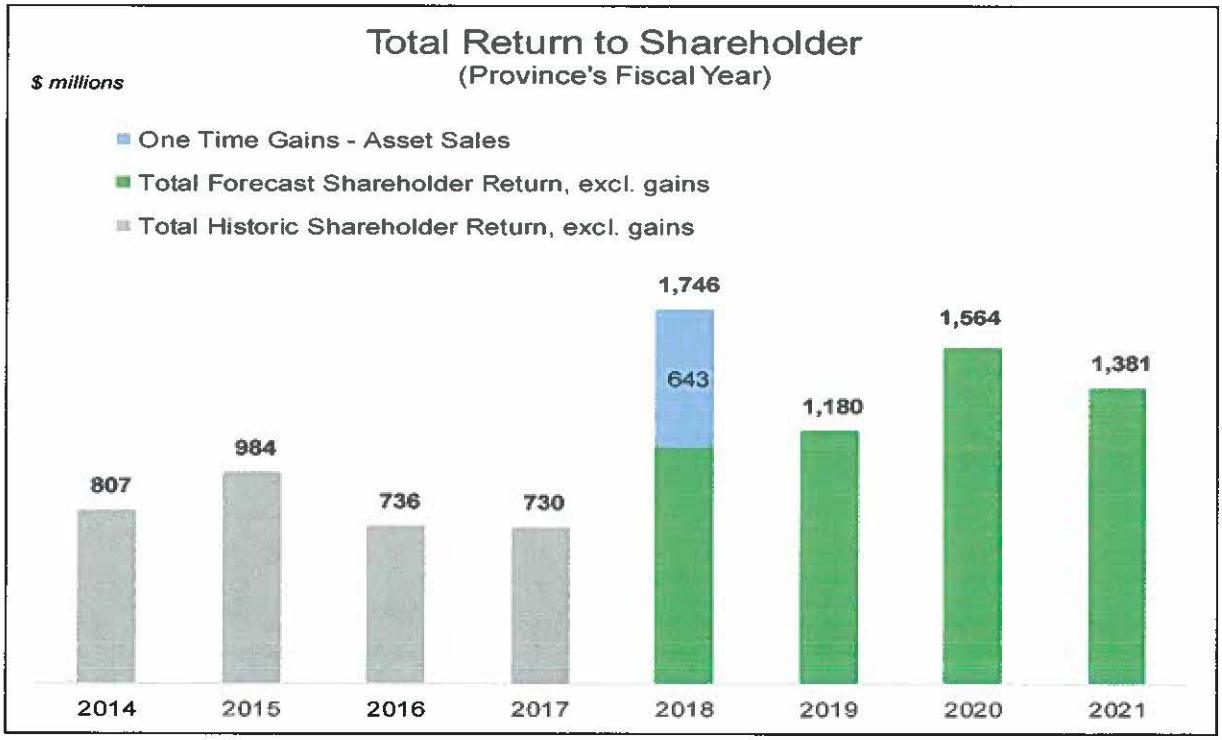
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

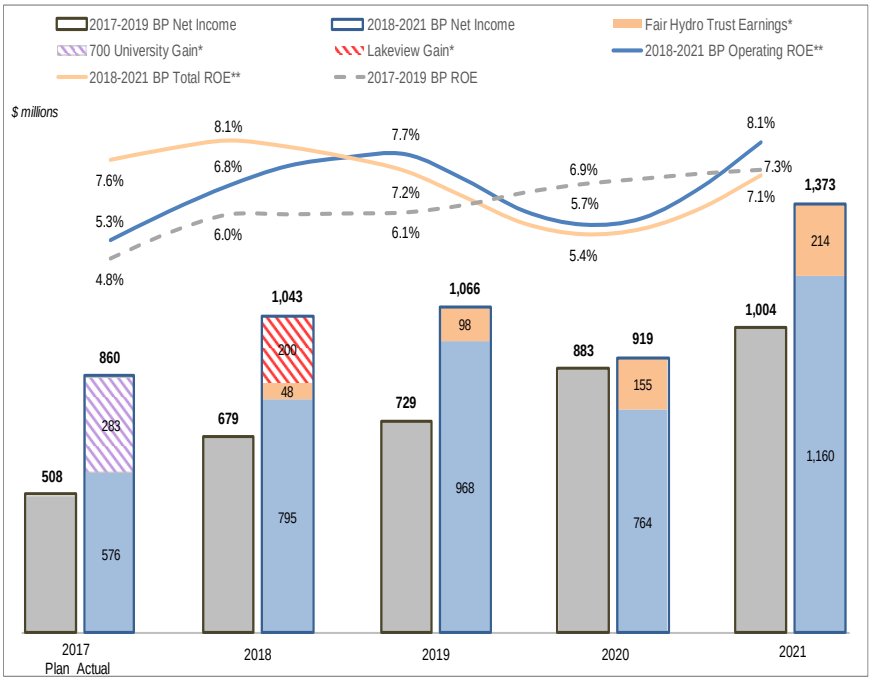
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

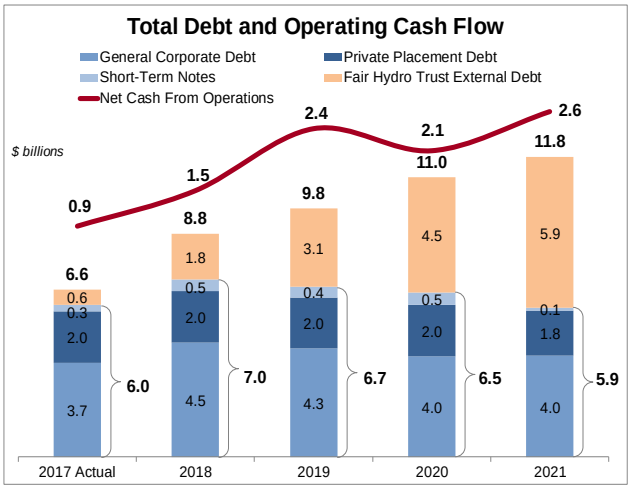
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

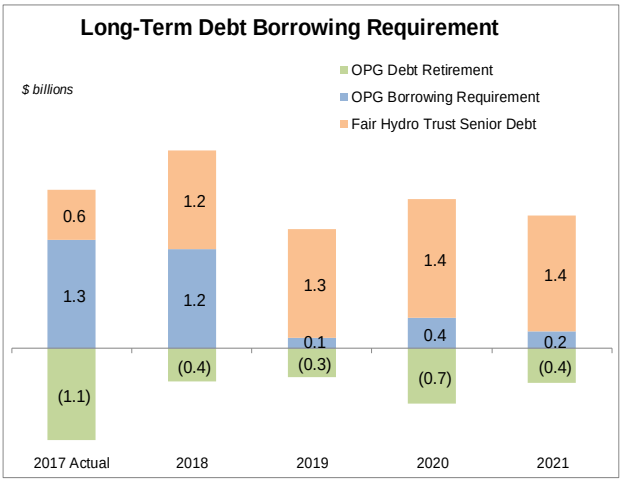
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

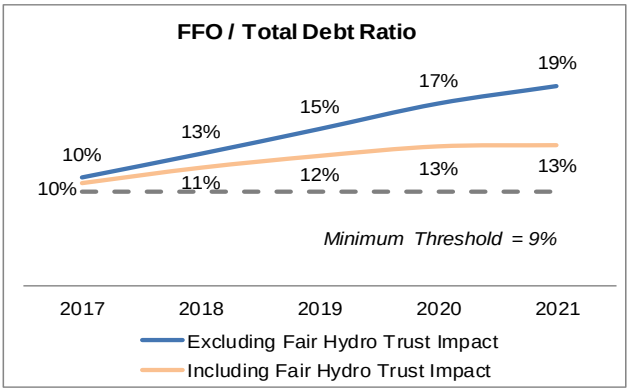


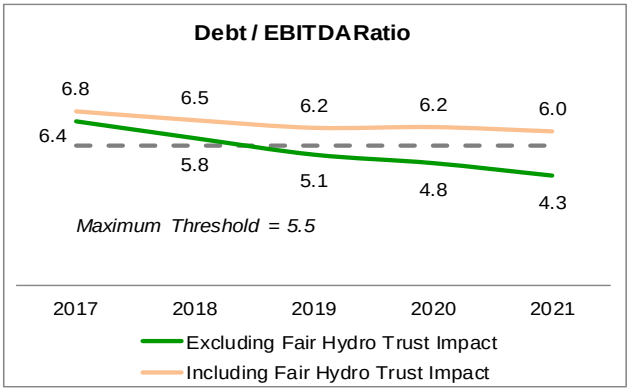

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



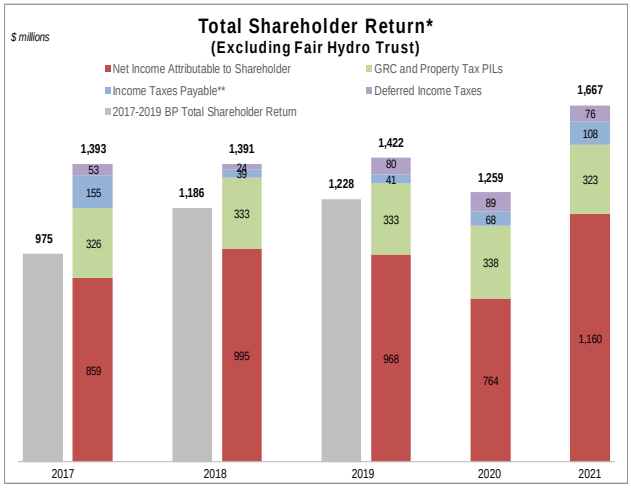

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

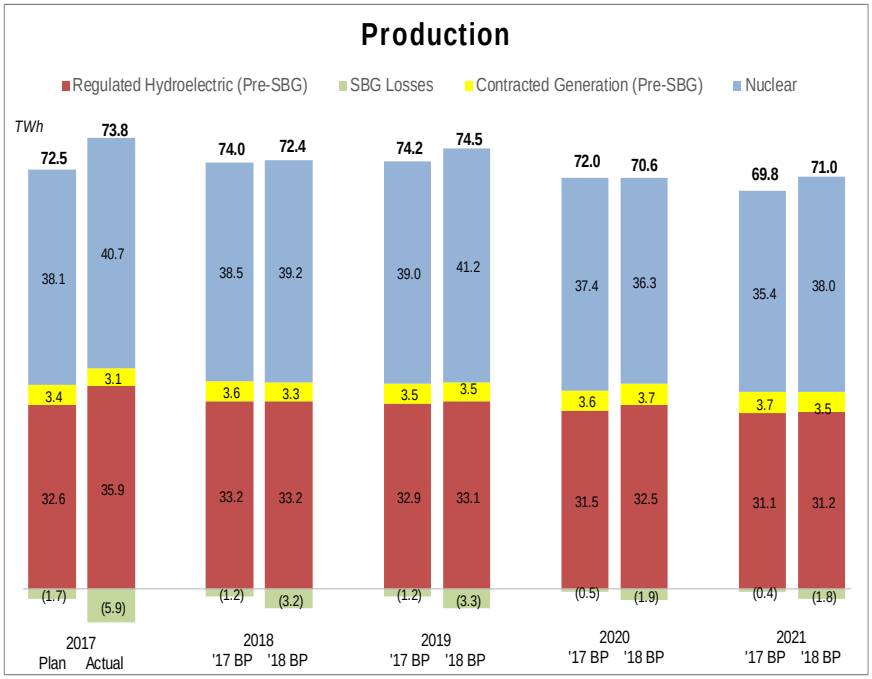
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

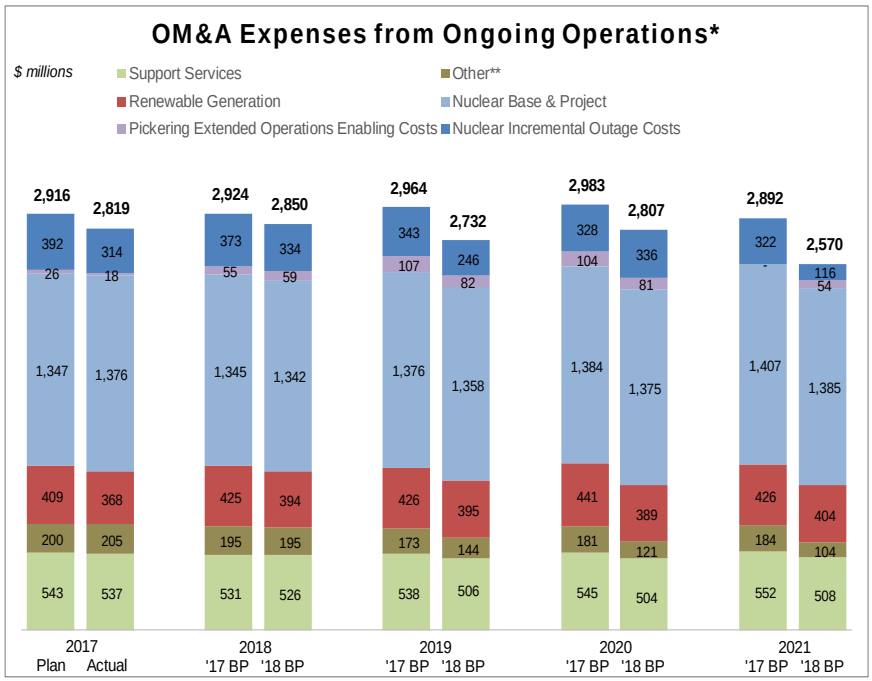
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

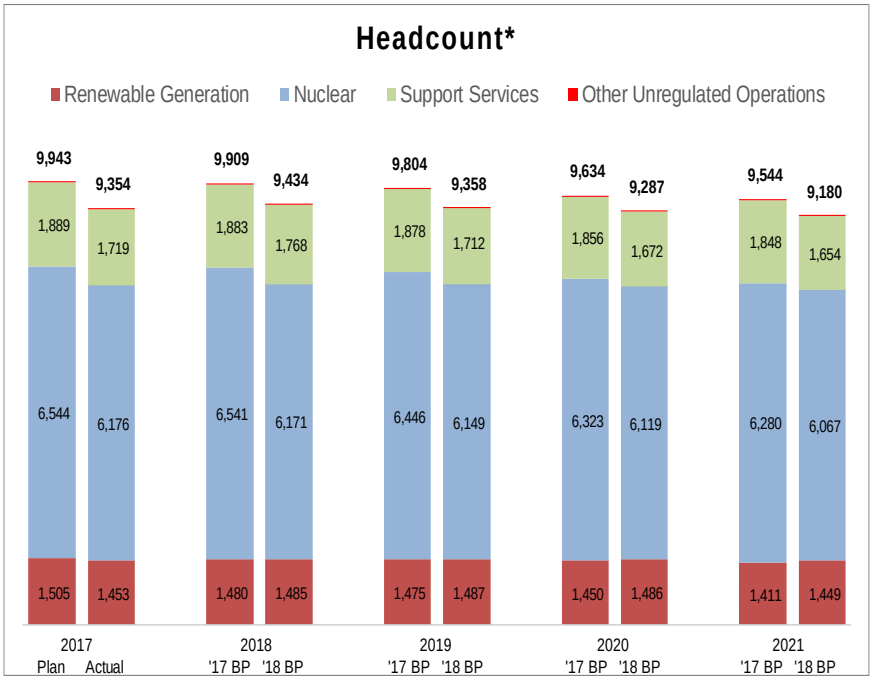
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

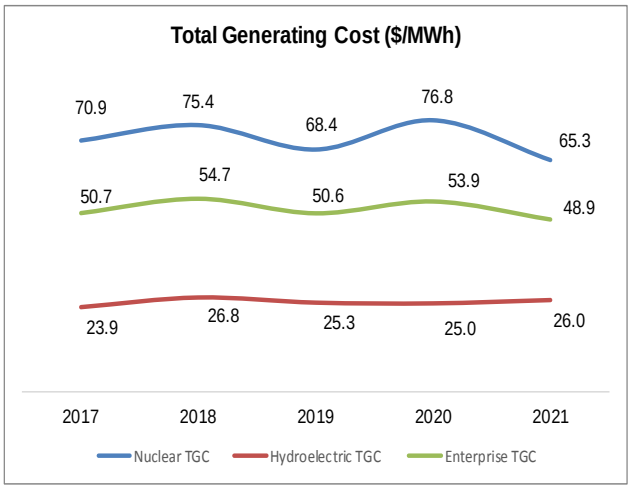
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

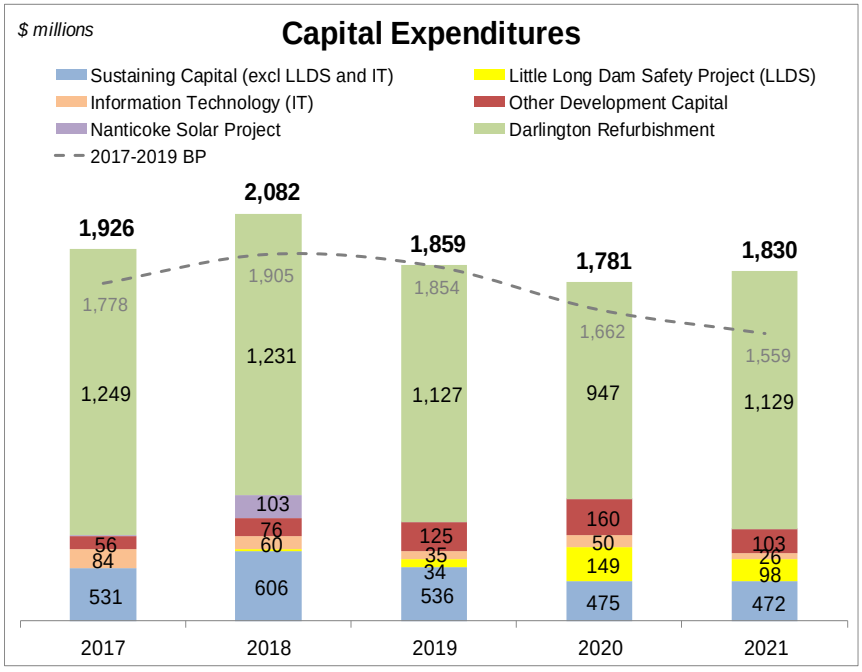
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

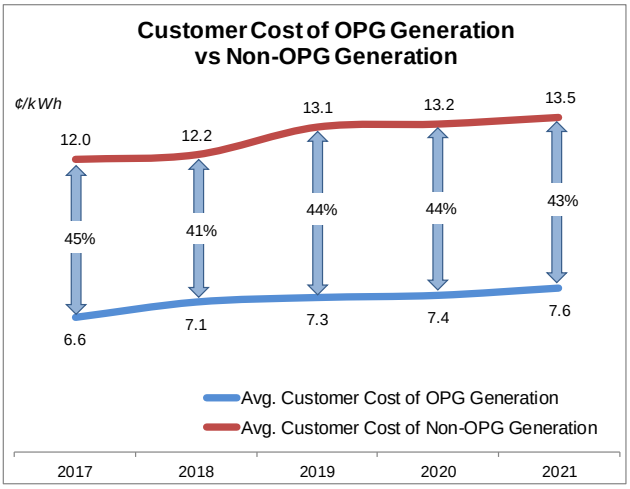
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 3 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

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bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

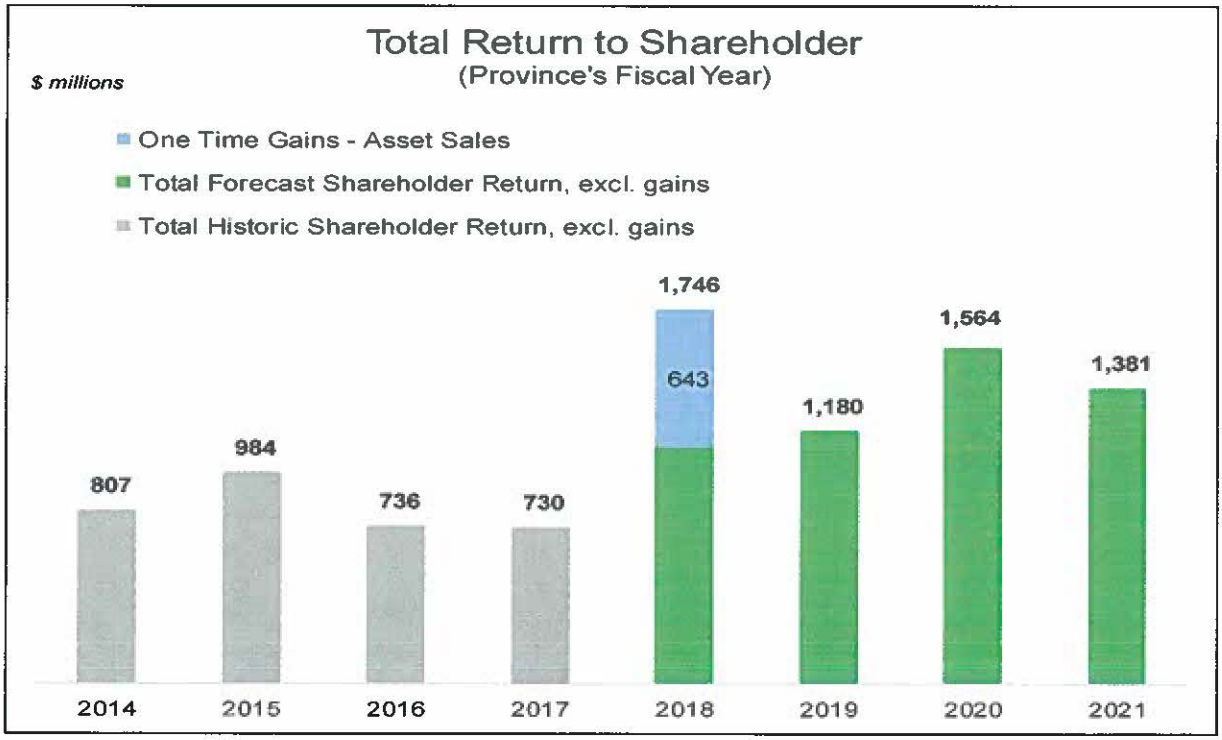
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

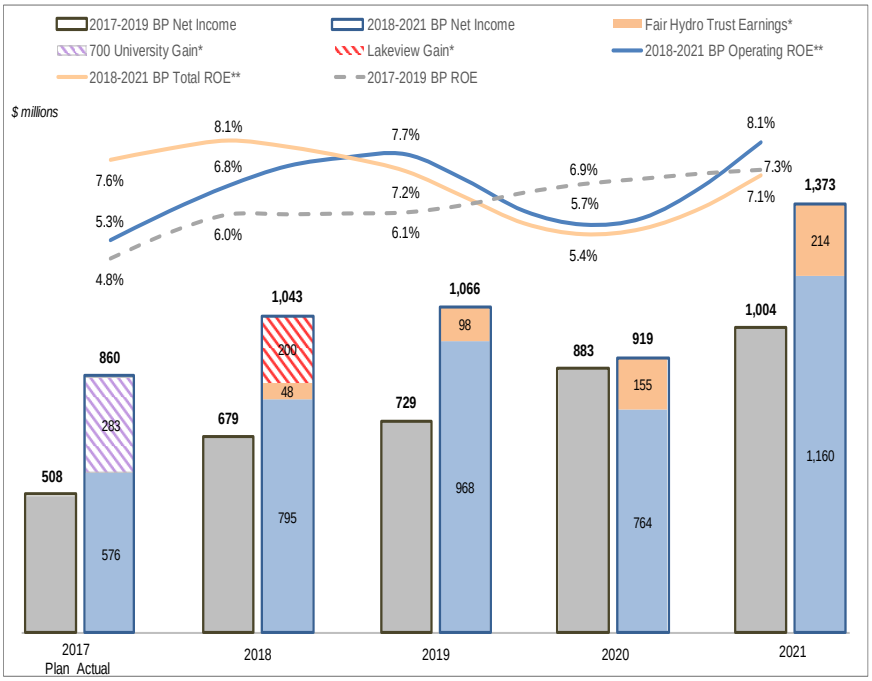
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

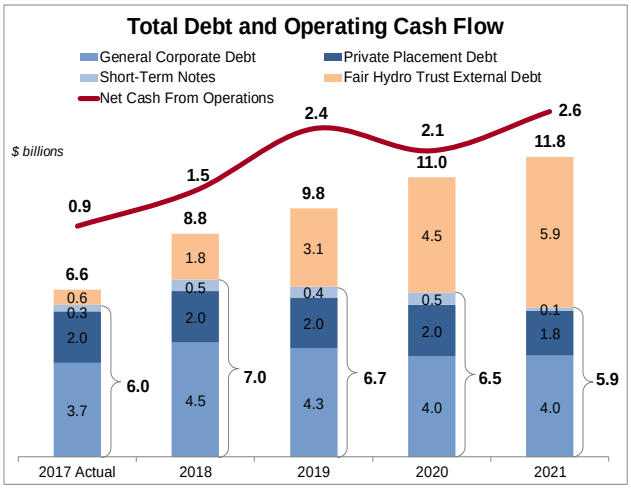
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

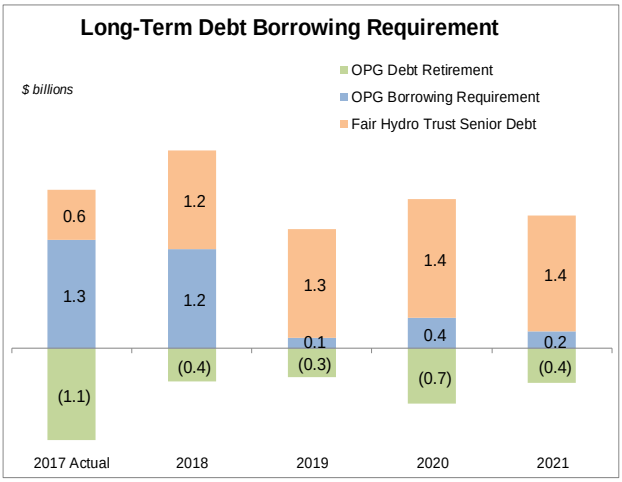
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

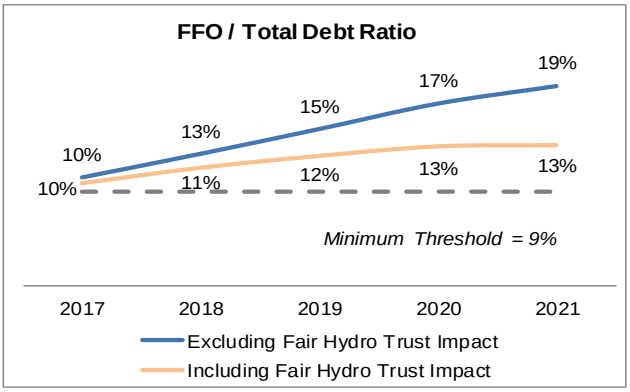


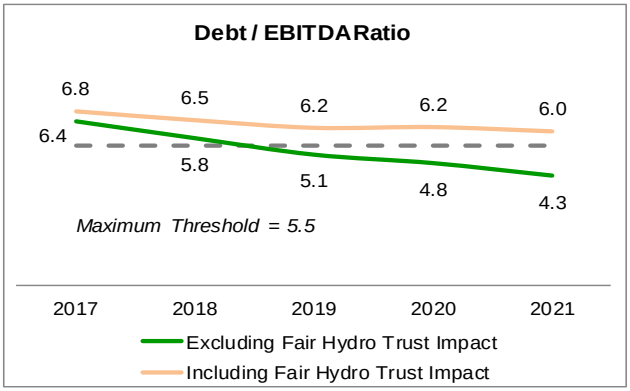

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



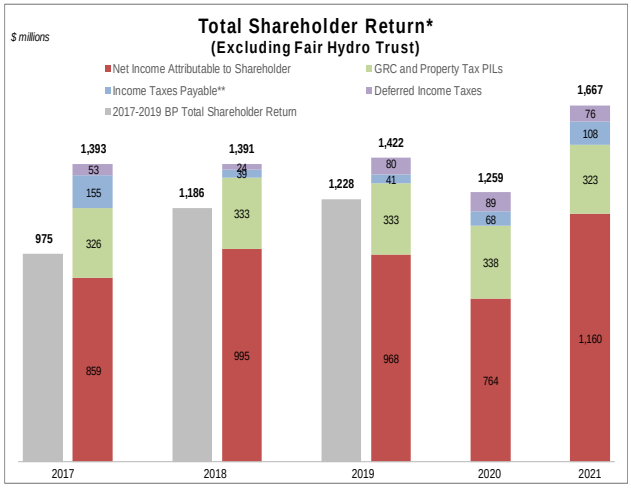

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

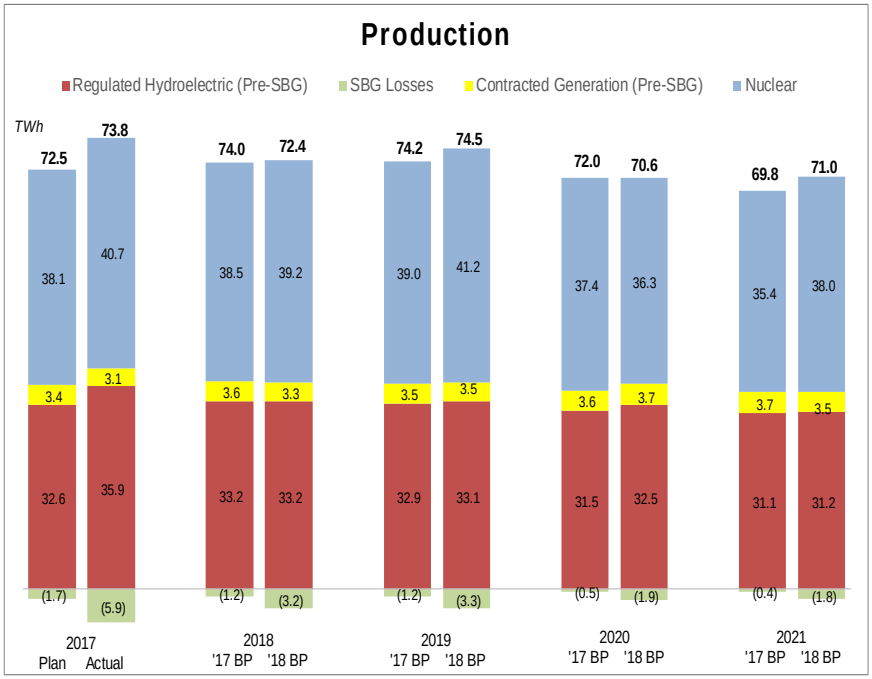
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

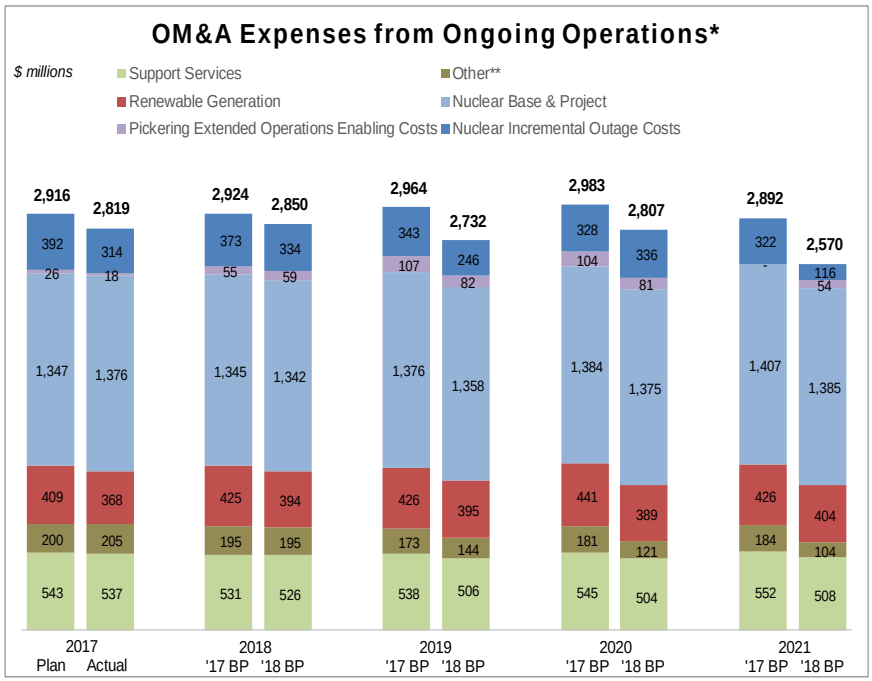
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

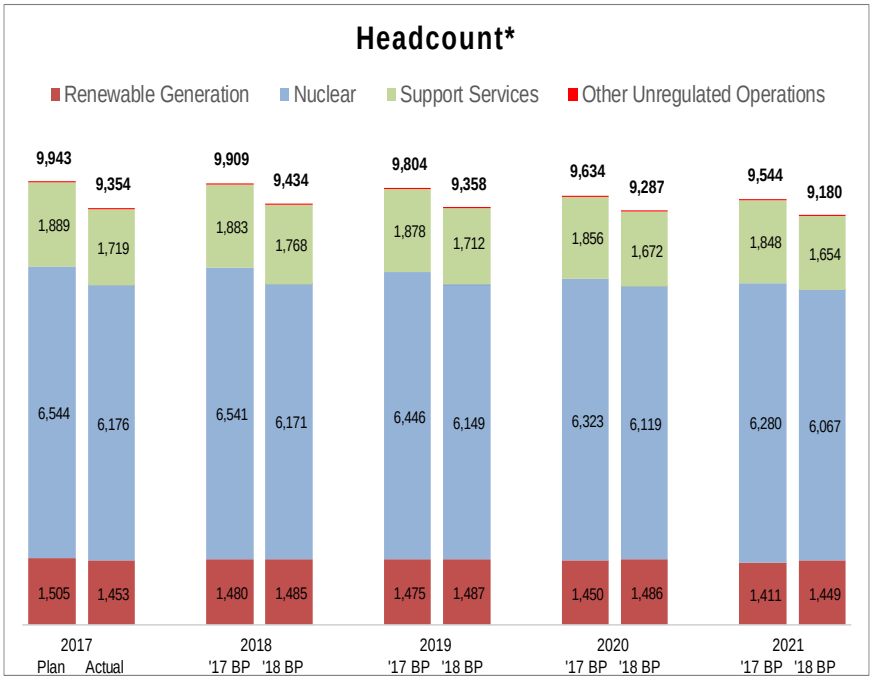
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

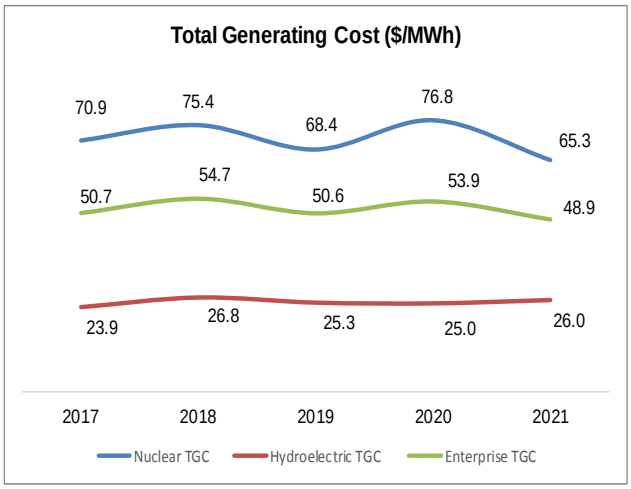
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

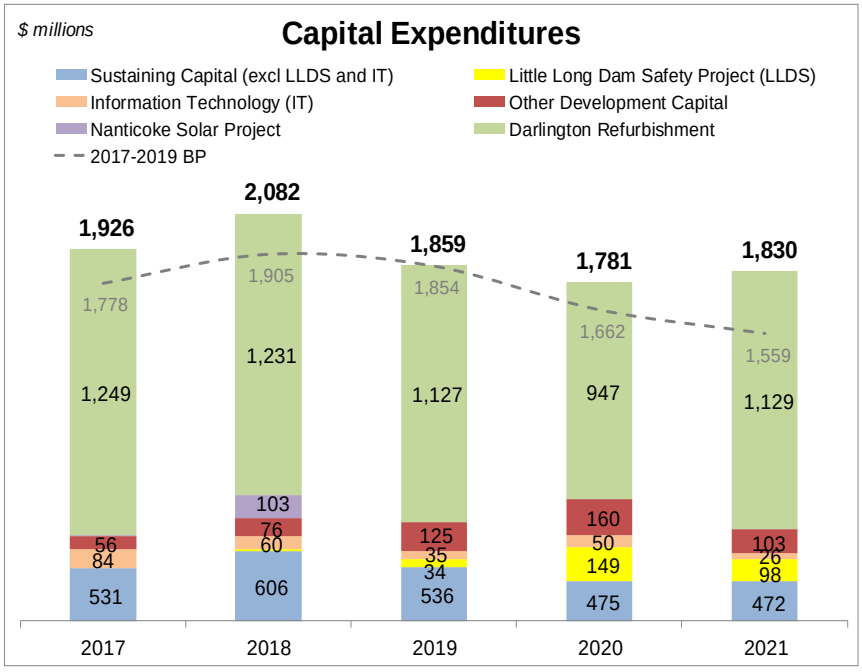
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

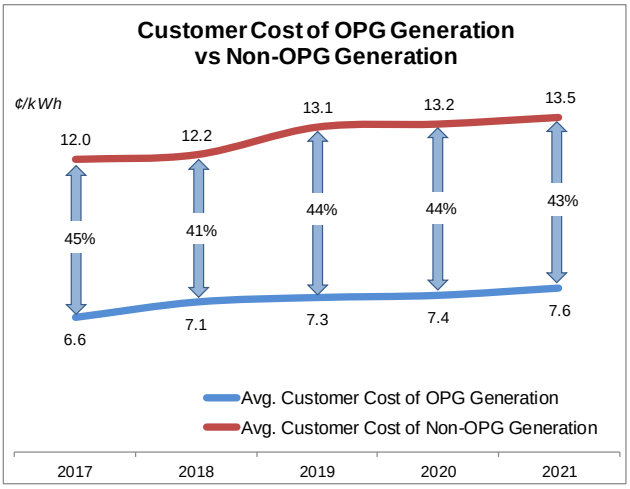
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 3 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

**Tel: 416-592-2115**
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

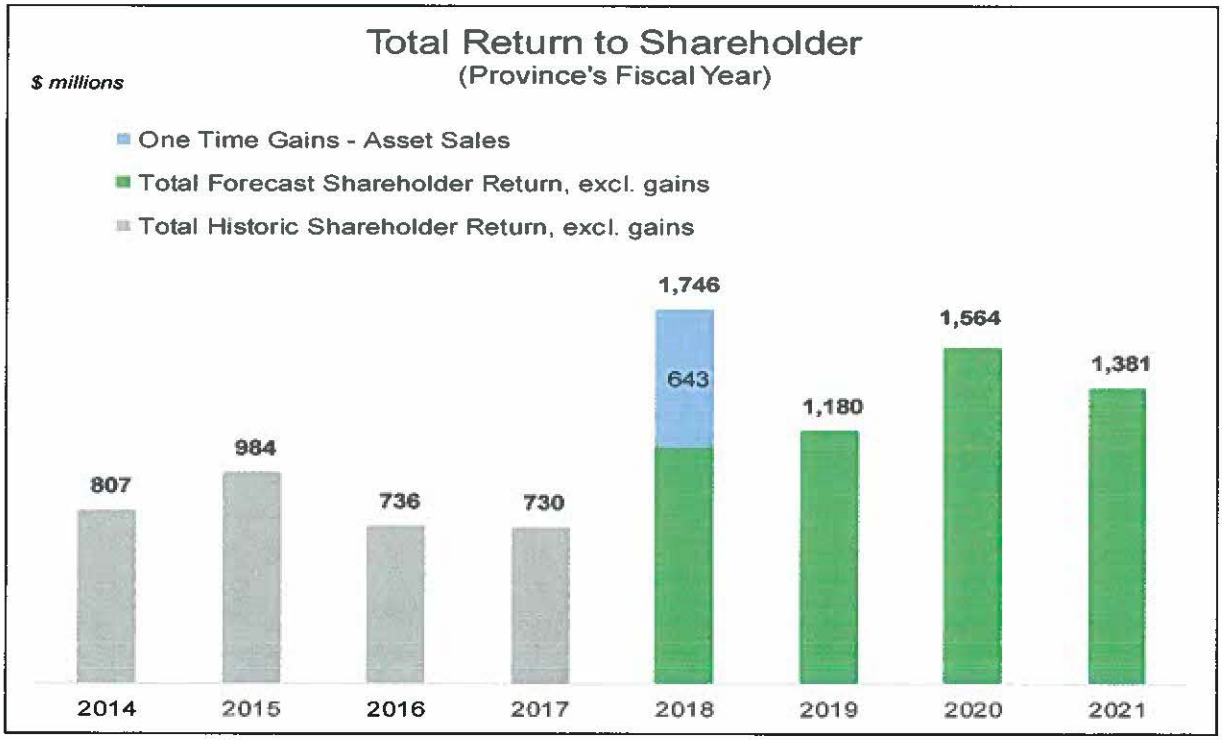
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

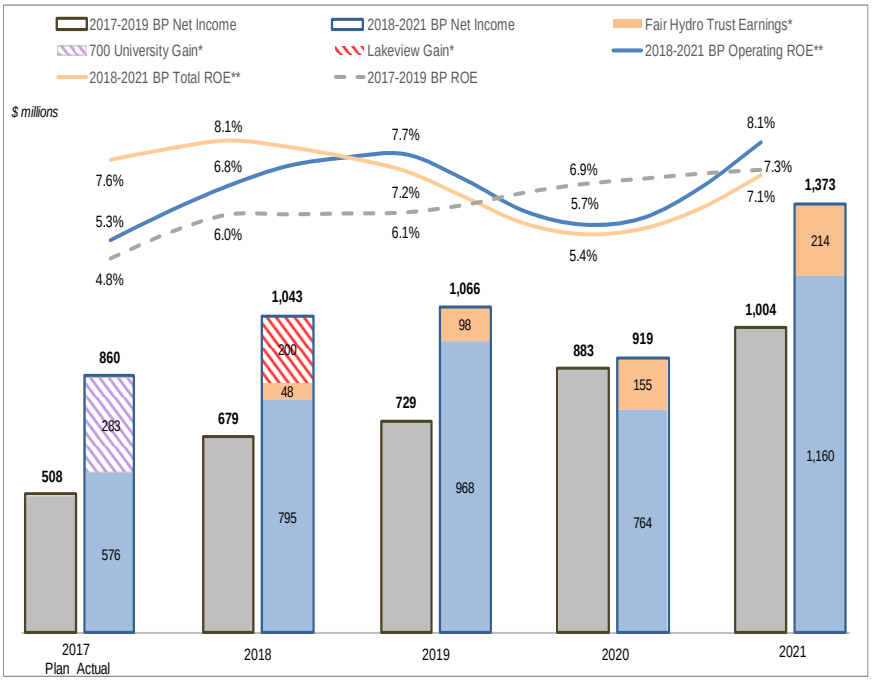
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

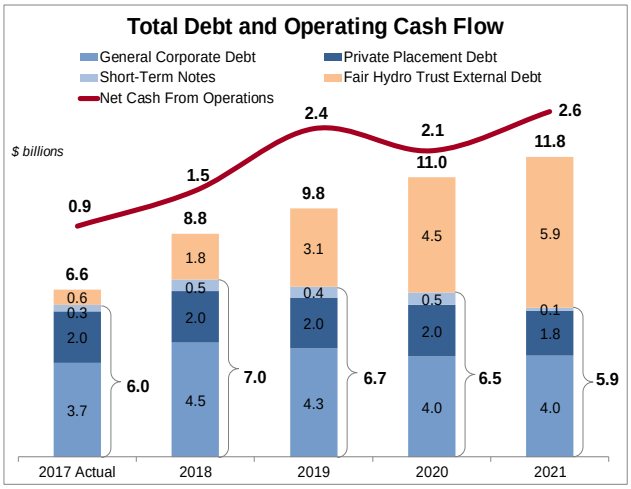
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

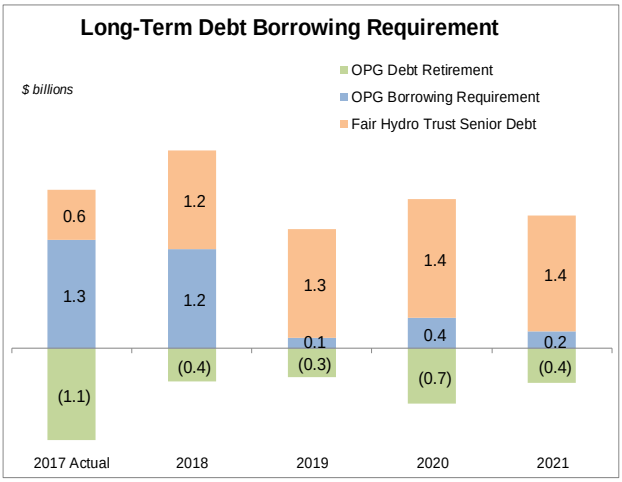
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

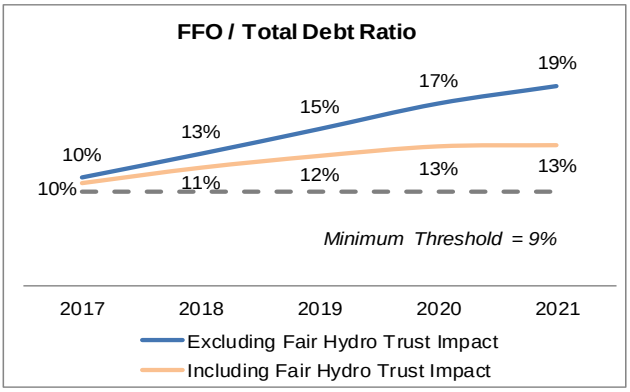


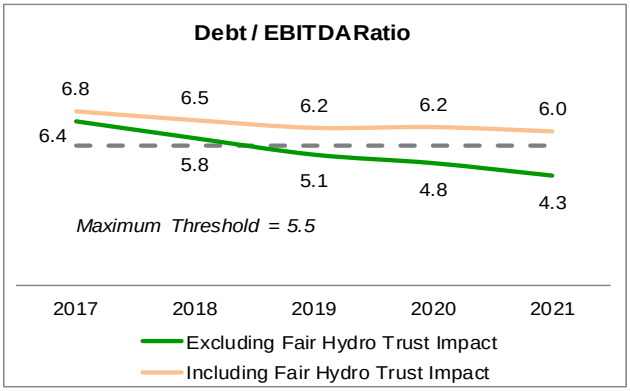

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



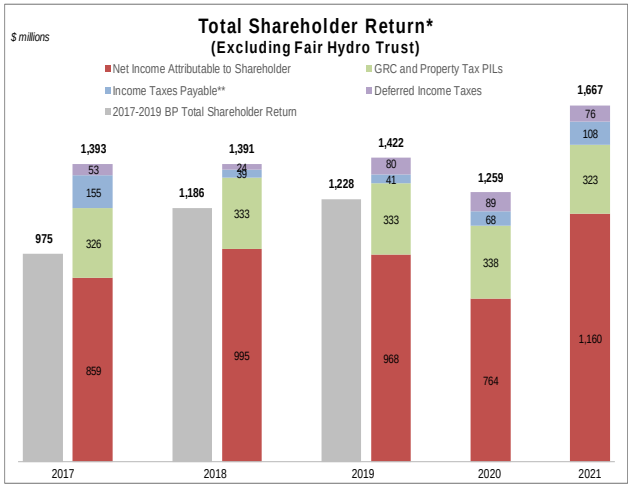

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

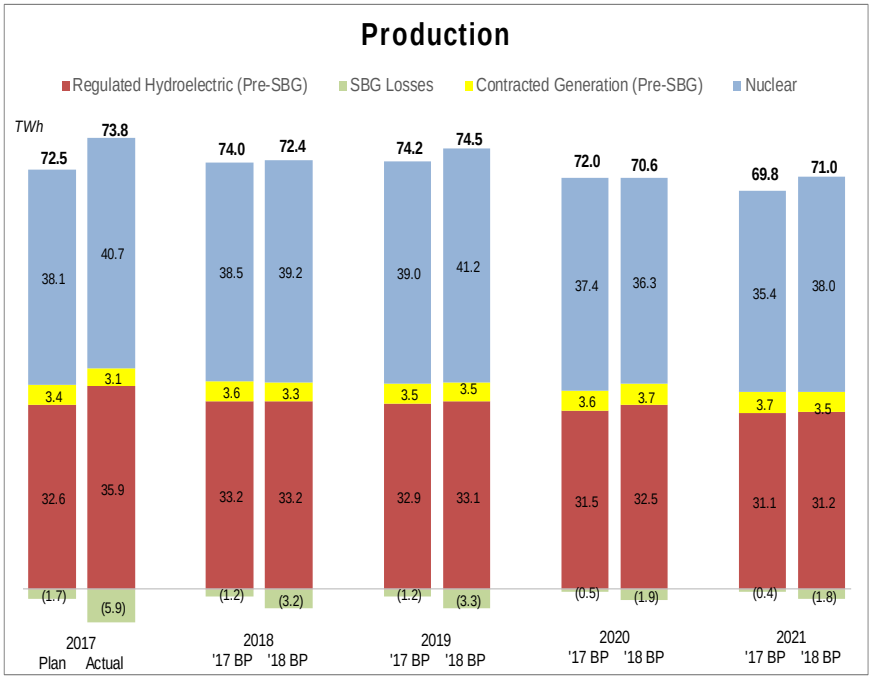
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

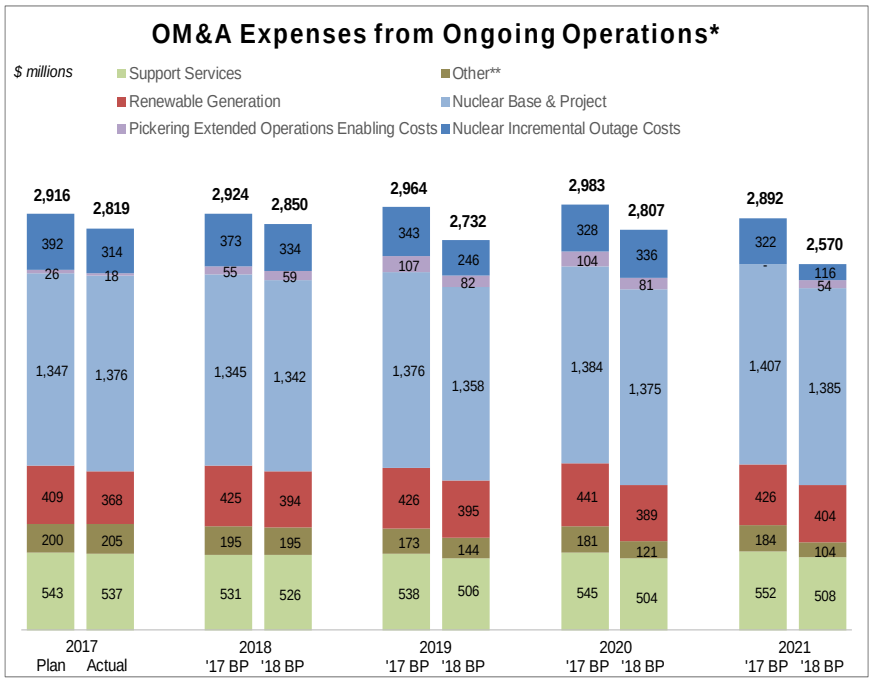
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

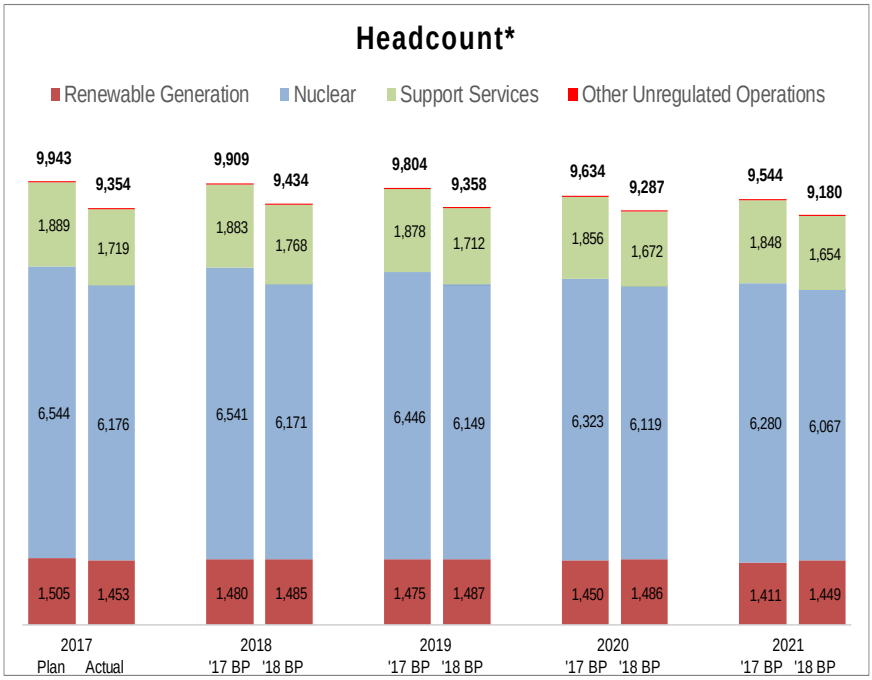
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

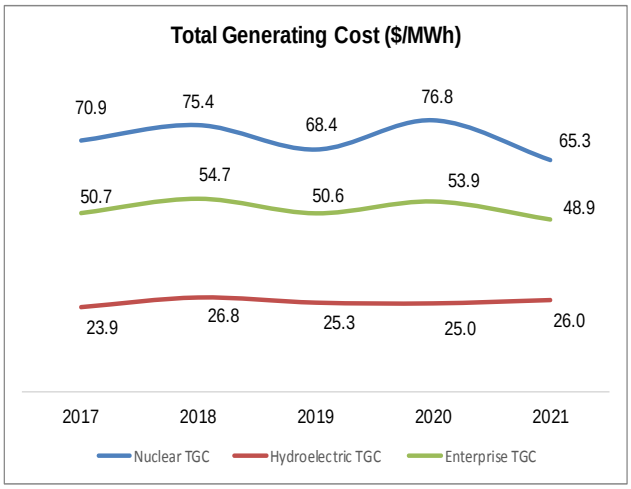
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

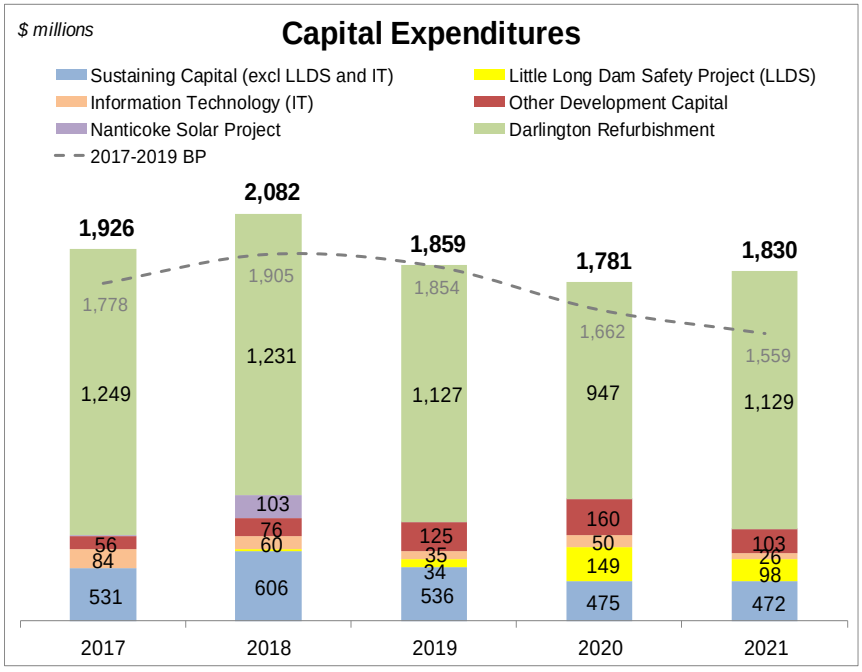
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

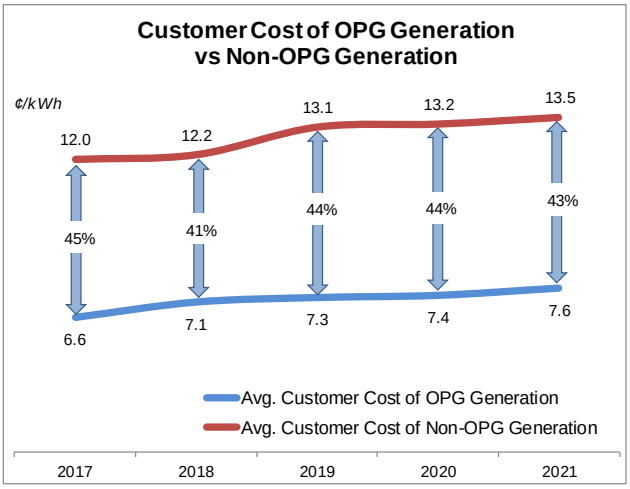
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 3 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

ONTARIO POWER GENERATION

**Bernard Lord**
Board Chair

700 University Ave, Toronto, ON M5G 1X6

**Tel: 416-592-2115**
bernard.lord@opg.com

February 12, 2018

The Honourable Glenn Thibeault
Minister of Energy
4th Floor, Hearst Block
900 Bay Street
Toronto, Ontario
M7A 2E1

Sent by email

Dear Minister,

On behalf of the OPG Board of Directors (the Board), I am writing to provide you with OPG's 2018-2021 Business Plan (the Plan) which was approved by the Board at its meeting on February 12, 2018, in fulfillment of our 2015 Memorandum of Agreement.

***Highlights of the 2018-2021 Business Plan:***

Overall, the 2018-2021 Business Plan shows improvement compared to last year's business plan in large part due to efficiency efforts on Operations Maintenance & Administration (OM&A) costs and improvements and optimization in our generation forecast. This plan fully reflects the outcome of the OEB Decision on OPG's base regulated rates. This is the first such business plan with OPG operating under incentive regulation for regulated hydroelectric assets and a custom incentive regulation approach for regulated nuclear assets. The key highlights of the business plan, excluding the impact of the Fair Hydro Plan, on a calendar year basis, are as shown in the table below:

| | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder, excl. Fair Hydro Trust *($ millions)* | 859 | 995 | 968 | 764 | 1,160 |
| Total Return to Shareholder, excl. Fair Hydro Trust *($ millions)* | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| Return on Equity, excl. Fair Hydro Trust | 7.7% | 8.5% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

The final revenue rates for OPG are still to be finalized by the OEB. The OEB Decision on revenue requirements was released December 28, 2017. A draft Payment Amounts Order (PAO) was submitted by OPG on January 17, 2018. Subsequent Intervenor and Board staff submissions were made and OPG filed its Final Reply to the PAO process on February 5, 2018. A final decision on the payments process, that will determine OPG's cash flow through rates, will be issued by the OEB sometime in the first half of this year. The payments process is more complicated than in previous applications as it must reflect a rate smoothing proposal that meets the intent of the updated O. Reg 53/05 that aims to make smoother customer bills. Smoothing does not impact OPG's financial commitments to the Province.

Total Return to Shareholder (the combination of Net Income, Income Tax and non income tax PILS) is forecast to be $5.9 billion for the fiscal years ended March 31, 2018 to 2021 as noted in the table below:

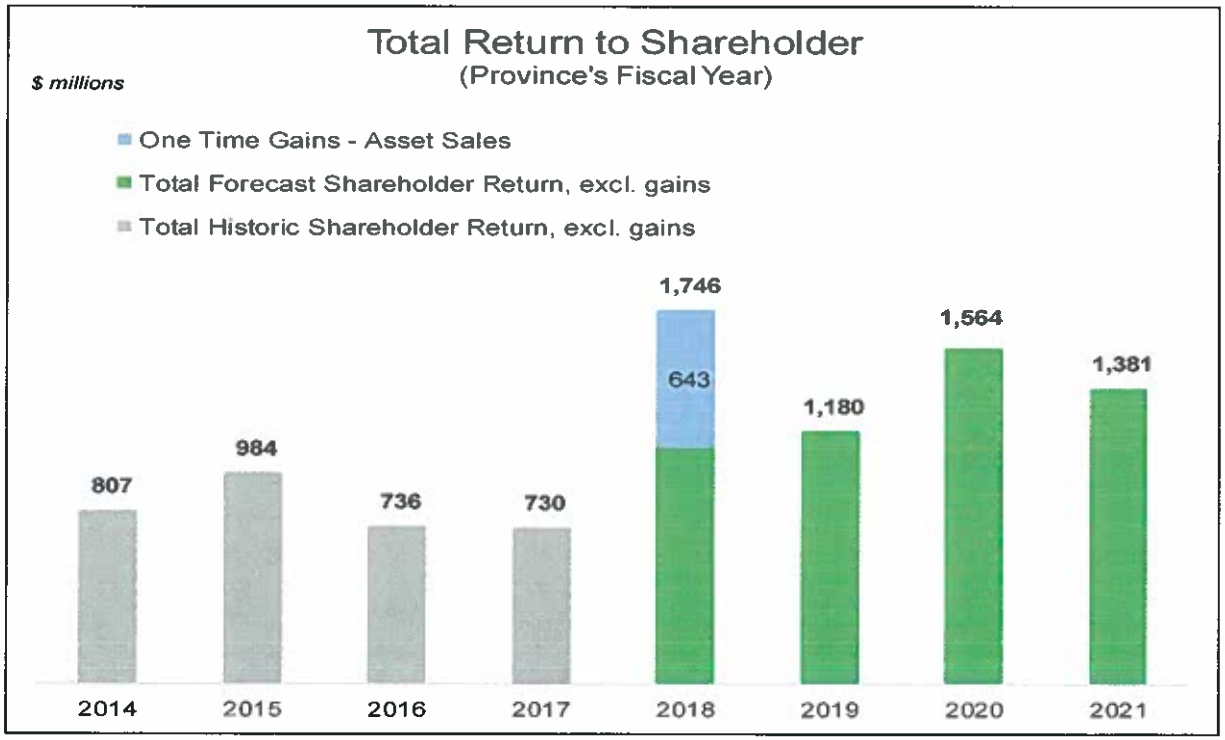
**Total Shareholder Return**

| *$ millions* | 2018* | 2019 | 2020 | 2021 | Total |
|---|---|---|---|---|---|
| **Net Income Attributable to Shareholder** | **1,195** | **795** | **1,053** | **877** | |
| **Non Income Tax PILs** | | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 | |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 | |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 | |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 | |
| **Total Non Income Tax PILs** | **330** | **331** | **336** | **335** | |
| **Income Tax PILs** | **221** | **54** | **175** | **169** | |
| **Total Shareholder Return**** | **1,746** | **1,180** | **1,564** | **1,381** | **5,871** |
| **Improvement from 2017-2019 Business Plan** | **528** | **4** | **307** | **-** | **838** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$270M; Net Income ~$200M)

** Excludes EBT from Fair Hydro Plan of $10M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

The fiscal results achieved in the 2018-2021 Business Plan reflect an improvement of over $800M compared to last year's plan for the fiscal years 2018 – 2020. In fact, since 2014 when our financial commitments were first communicated using the Total Return to Shareholder metric, OPG's results have been stable as seen in the chart below and are forecast to show a positive trend over the plan period.




While the OEB Decision disallowed a variety of revenue requirement items, OPG has taken proactive steps that will help mitigate a large portion of those disallowances including:

- Reducing over $600M in OM&A costs between 2018 and 2021 through cost cutting and efficiency measures. These steps will also help position OPG to be a more efficient operator, particularly in planning for the ultimate shutdown of the Pickering generating station in 2024.
- Leveraging off the excellent performance of Pickering and outage execution in general in the nuclear fleet, generation improvements are planned from nuclear and reflected in the forecast

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- Continuing to invest in our hydroelectric operations to optimize performance and availability to increase generation output from the hydroelectric assets

OPG remains focused on delivering projects safely, with high quality, on time and on budget. Major development projects over the Plan period are consistent with the recent 2017 LTEP, and include:

- Continuing and completing the refurbishment of the first *Darlington* unit (Unit 2), on time and on budget;
- Commencing the execution phase of the second Darlington unit (Unit 3) for refurbishment;
- Expansion of the *Ranney Falls* hydroelectric station in 2017/18 and other smaller hydroelectric redevelopments;
- Execution of dam safety upgrade initiatives at Lower Mattagami;
- Completion of the 44 MW Nanticoke solar project by 2019; and
- Investments of $200 million in organic growth opportunities leveraging OPG's core competencies beyond the current core generation portfolio.

With respect to the Darlington Refurbishment project, OPG is satisfied that the OEB agrees with the company's position that the program is a well planned, well controlled large project and that the OEB has agreed to put into service the $4.8 billion costs of Unit 2 as tabled by OPG in addition to the $0.4 billion in remaining pre requisite projects excluding the Heavy Water Storage and Drum Handling Facility. Combined with projects that have been placed into the rate base previously, total life to date in-service capital from Darlington Refurbishment will be approximately $5.5 billion by the time Unit 2 is completed.

In terms of impact to customers, OPG's payments application would result in a typical residential customer bill increase of $0.65 per month per year over the 5-year rate period. In return, the first of the four Darlington units will have been refurbished, providing decades of clean, reliable supply of electricity at a cost lower than other alternatives; a fact that was validated by the Financial Accountability Office's report on refurbishments in Ontario that was issued in November 2017. In addition, the life of Pickering will have been extended through 2024, reducing customer cost by over $600 million. The cost to customers of electricity generated by OPG during this period is expected to remain approximately 40% below the average non-OPG cost of electricity in Ontario.

***Critical Factors in the 2018-2021 Business Plan***

There are a number of factors that impact achieving this Business Plan that I would like to bring to your attention.

- **Pickering Relicensing:** The Plan reflects the continued investment and work required to support the continued operations of the Pickering plant until 2024 with CNSC approval. The OEB has confirmed and accepted the incremental investment required to achieve the extended operating life for the station and the economic regulatory risk has been greatly reduced. The needed work to ensure the ability to operate the units longer is being executed through upcoming outages at the station. While this critical work is ongoing, the nuclear business has been able to execute outages as planned and has optimized outage schedules to increase reliability and generation output from the plant. A key piece to complete the path forward for Pickering will be success at the upcoming hearing with the CNSC to renew the station's operating license. The existing license is set to expire at the end of August 2018. A 10 year operating license is being sought that would see the plant through to its end of commercial operations as well as allow for the defueling and other key work required to safely lay up the units. Support from across the company and from stakeholders will be crucial as part of the relicensing exercise. The benefits of an extended Pickering station life include reduced $CO_2$ emissions, support for lower smoothed nuclear rates during refurbishment of Darlington, and continued employment for the approximate 4,000 staff impacted by a Pickering closure. An earlier closure of the station would not deliver the benefits noted and would trigger severance and other closure related costs that would put upward pressure on customer prices.

- **Continued support for Darlington refurbishment efforts:** OPG is approaching the mid point in the schedule for refurbishment of Unit 2 and the project is tracking on time and on budget. While the subsequent unit planned for refurbishment (Unit 3) will not commence execution until Unit 2 is successfully returned to service by February 2020 at the latest, planning efforts and acquisition of long lead time materials must continue. To end of 2017, $93 million has been spent on planning activities for Unit 3 with a further $540 million planned over the 2018 – 2020 period prior to breaker open. OPG

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is pleased that the Province has agreed with OPG's assessment of progress to date and is not exercising an "off ramp" for Unit 3. This is another clear milestone for the project and OPG is looking forward to continued support from the Province that will culminate in the refurbishment of all 4 units within the overall budget of $12.8 billion.

- **Collective Bargaining impacts:** 2018 is a watershed year in terms of setting a path forward with our unionized workforce. The OEB, in its Decision, sent clear signals that the cost basis of OPG's regulated operations does not benchmark favourably on several fronts including compensation and in portions of corporate support costs. The fact that our total compensation for our unionized workforce, inclusive of pension and benefits, benchmarks above median sends a clear mandate to address these issues as part of collective bargaining. While such changes are difficult to achieve, 2018 offers a key opportunity in that both agreements with the Power Workers Union and the Society of Energy Professionals come due during the year.

- **Fair Hydro Plan:** The end of 2017 marked the commencement of OPG's involvement as the financial services manager for the Fair Hydro Plan. Over time, additional equity infusion from the Province will be made in part to finance portions of the global adjustment deferred asset that is being acquired from the IESO. Through this process, OPG will earn financial returns, mainly from the Province's incremental equity investment, that will be returned to the Province via increased net income. As disclosed in the footnote to the Total Shareholder Return forecast above, those amounts become larger as more of the deferred Global Adjustment asset is acquired by the Fair Hydro Trust, reaching $225 in net income by 2021.

- **OPG's Capital Allocation:** The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the company well for developing a portfolio of organic and external investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations.

OPG's 2018-2021 Business Plan sets ambitious but achievable goals and targets, and will deliver increased value to the Shareholder and Ontario electricity customers. OPG has demonstrated stable returns to the shareholder over the past 5 years and the 2018-2021 Business Plan forecasts a positive, increasing trend.

With the regulatory certainty provided by the OEB in its recent decision, the path forward for OPG is clear: to continue to provide reliable, safe and economic generation of electricity while challenging existing cost structures to drive enhanced efficiencies. OPG will achieve this while staying focussed on the successful execution of Darlington refurbishment and looking for growth opportunities to leverage existing operational strength. OPG's current business portfolio is heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. Although perceived as relatively low risk, this lack of diversification increases OPG's overall business viability risk. Diversifying OPG's business by developing a portfolio of options of future storage, gas, solar, hydroelectric and nuclear opportunities inside and outside of Ontario, focusing on innovation including investments in disruptive innovation, and investigating potential extensions to OPG's business is necessary to reduce OPG's overall business viability risk over the long term. With its strong financial position, OPG will continuously monitor for business growth opportunities and, where appropriate and with the support of the Shareholder, act as needed in order to maintain OPG's scale as a valuable public asset.

Sincerely,



Bernard Lord

cc. OPG Board of Directors
Serge Imbrogno, Deputy Minister of Energy

Enclosure

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# OPG's 2018-2021 Business Plan

***February 12, 2018***

ONTARIO POWER GENERATION

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## Overview

OPG's 2018-2021 Business Plan is focused on continuing to drive sustained value for the Shareholder and customers in line with the Company's strategic direction and builds on the progress made to date in advancing the underlying strategic imperatives of operational excellence, project excellence, financial strength and social licence. The plan is aligned with Ontario's 2017 Long-Term Energy Plan (LTEP), through continuing to execute the Darlington refurbishment, implement plans for Pickering continued operation to 2024, invest in hydroelectric fleet upgrades and development, and pursue commercial innovation strategies in the electricity sector. The plan reflects the Ontario Energy Board's (OEB) December 28, 2017 decision on OPG's 2017-2021 regulated rates and includes preliminary, unaudited results for OPG's 2017 fiscal year. Financial information presented includes the impact of consolidating the Fair Hydro Trust established in December 2017 to finance Ontario's Fair Hydro Plan.

The plan is underpinned by the Company's strategic direction that seeks to deliver an appropriate return on the Shareholder's investment in OPG, while maintaining the Company's position as the low cost provider of safe, clean and reliable electricity in Ontario. The plan makes progress toward achieving these strategic priorities by implementing key enterprise and business unit level initiatives and by establishing goals to drive plan-over-plan improvement in operational and financial performance. The plan builds on OPG's strong performance in 2017, seeking to maximize the value of existing assets by continuing to further improve fleet performance and optimize nuclear outages during a period of relative regulatory certainty provided by the OEB's recent decision. At the same time, the plan recognizes that the OEB's decision to disallow certain operations, maintenance and administration (OM&A) expenses, in large part based on benchmarking results for OPG's historical cost and operating performance, and reduce capital funding for the nuclear business will challenge OPG's ability to earn the target rate of return on the Shareholder's investment, absent changes to the Company's current cost structure.

OPG's ability to successfully deliver on the strategic direction requires a realignment of the Company's cost structure and operating model in order to further improve the cost performance of the core generating fleet, including corporate support functions. Continuous improvement in operational and cost performance should support more favourable outcomes of future OEB decisions. Longer-term success also requires a platform for material strategic investments to maintain and enhance OPG's scale, risk profile and energy industry leadership across carbon-friendly technologies, particularly as the Company prepares for post-Pickering operations. This includes continuing to take steps to enhance the Company's sustainable footprint in line with the Company's social licence strategic imperative. In pursuing these strategies, an absolute priority for OPG remains maintaining a strong nuclear and public safety record, while delivering the Darlington refurbishment on time and on budget.

The financing of the Fair Hydro Trust impacts OPG's net income and return profiles. In order to evaluate performance plans and results on a comparable basis, additional financial metrics are required within OPG's operations. In the discussion that follows, the following terms are used to describe OPG's financial performance:

- ***Net income*** and ***Total Return on Equity (ROE)*** are based on OPG's consolidated financial performance and corporate capital structure, including the impact of the Fair Hydro Trust;
- ***Operating net income*** and ***Operating ROE*** exclude the impact of the Fair Hydro Trust and exclude the gains on sale of 700 University Ave. property and the Lakeview site and corresponding dividend payments to the Shareholder from net income and corporate capital structure;
- ***Regulated ROE*** is return on OPG's regulated operations calculated using an equity thickness of 45%, as reflected in the deemed capital structure used by the OEB to set OPG's regulated rates.

Highlights of the 2018-2021 Business Plan are as follows:

- Operating net income and Operating ROE are trending upward over the period on higher nuclear production, lower OM&A costs, and rate base growth upon return to service of Darlington Unit 2;
- Operating net income and Operating ROE temporarily decline in 2020 due to the six-unit Pickering VBO and other major planned outages scheduled in the year;
- The Fair Hydro Trust contributes to increasing amounts of incremental net income as the total investment interest grows, driving down Total ROE due to Province's equity injections;

- Operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period, with OPG's debt ratio excluding Fair Hydro Trust dropping to 26% by 2021, assuming no acquisition investments;
- Net income and ROE in 2017 are adversely affected by a partial-year effective date of June 1, 2017 for new regulated rates.

| 2018-2021 Business Plan Summary | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income Attributable to Shareholder *($ millions)* | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder *($ millions)* | 576 | 795 | 968 | 764 | 1,160 |
| Total Return on Equity | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Regulated Return on Equity | Average of 8.2% over the 2017 to 2021 period | | | | |
| Debt Ratio, excl. Fair Hydro Trust* | 34% | 36% | 33% | 30% | 26% |
| Enterprise Total Generating Cost *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| Production (net of Surplus Baseload Generation) *(TWh)* | 73.8 | 72.4 | 74.5 | 70.6 | 71.0 |
| OM&A Expenses from Ongoing Operations *($ millions)* | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Capital Expenditures *($ millions)* | 1,926 | 2,082 | 1,859 | 1,781 | 1,830 |
| Total Headcount (Regular and Term Employees) | 9,354 | 9,434 | 9,358 | 9,287 | 9,180 |

*Excludes Class A Shares and Fair Hydro Trust Senior Debt

**Key Assumptions and Risks**

- Province's concurrence is received to proceed with the refurbishment of subsequent Darlington units, and the project continues to be executed consistent with the approved overall project budget and schedule. Failure to receive the concurrence or to meet project cost and schedule commitments could potentially result in significant write-offs against net income as well as reputational damage. Costs incurred for Darlington Unit 2 refurbishment and pre-requisite projects beyond total in-service amounts including contingency approved by the OEB for 2017-2021 will be subject to a future prudence review. The OEB has found that OPG's performance on the Darlington refurbishment should be evaluated at the overall program level rather than by individual component.
- Activities continue to be successfully carried out to enable Pickering continued operation beyond 2020, with a corresponding operating licence granted by the Canadian Nuclear Safety Commission (CNSC) by August 2018. Inability to extend Pickering operation beyond 2020 would result in advancement of significant employee downsizing and organizational restructuring impacts and station decommissioning expenditures, and require OPG to notify the OEB. Continuing Pickering operation has a moderating effect on OPG's nuclear rates.
- OPG's strategy to pursue non-organic expansion options including gas, solar and hydroelectric assets primarily outside of Ontario and potential extensions to the business must meet Shareholder's expectations. Lack of material growth investments and their commensurate contributions to scale, income and cash flow, together with a less diversified asset portfolio, will result in a loss of scale following retirement of Pickering, increase the risk of being unable to withstand significant variances or shocks to the business plan, diminish ability to support de-carbonisation policy and ultimately erode the value of Shareholder's investment.
- Future employee termination costs associated with the Pickering end of commercial operations are not included in the business plan. Accounting criteria requiring recognition of a liability for these costs are currently assumed to be met during the next nuclear rate-setting period, commencing in 2022. Recognition of the costs prior to 2022 would require assurance over their future recovery in order to avoid a significant charge against net income.

- Inability to retain and attract leadership talent and qualified management employees could adversely impact the execution of Darlington refurbishment, continued Pickering operation and other strategic priorities. Management and staff must continue to adapt to OPG's evolving corporate culture and higher level of commercial discipline, including commercial implications of the recently established public debt platform.
- OPG continues to report its financial results under United States generally accepted accounting principles (US GAAP) rather than International Financial Reporting Standards (IFRS), with the Ontario Securities Commission expected to grant an extension to the exemption allowing OPG to prepare its consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant volatility in OPG's net income compared to US GAAP.
- OPG's pension, OPEB and nuclear waste obligations, and related funds are exposed to financial market conditions. The plan assumes that the funds perform according to long-term expectations.

Further details of the key planning assumptions for the 2018-2021 period are found in Appendix 1 and additional key risks to the plan are identified in Appendix 2.

**Net Income, Total Shareholder Return and Customer Price**

Total net income attributable to the Shareholder is forecast to grow from $860 million in 2017 to $1,373 million in 2021, reflecting regulated rates based on the OEB's 2017-2021 rate decision inclusive of a significant increase in rate base upon return to service of Darlington Unit 2, continuous operational improvement, and the impact of the Fair Hydro Trust. This includes a plan-over-plan increase of ~$390 million in 2018-2021 Operating net income. The planned net income levels are critically dependent on OPG's ability to achieve targeted OM&A cost reduction and production goals set out in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

Successful execution of the business plan will allow OPG to contribute $5.7 billion in earnings and taxes to the Shareholder over the 2018-2021 period, excluding the impact of the Fair Hydro Trust, while continuing to substantially mitigate the cost of electricity in the province. The overall customer cost of OPG's generation, taking into account the impact of the OEB's 2017-2021 rate decision, will continue to track approximately 40% below other generators in Ontario. Per OPG's proposed payment amounts order filed with the OEB in January 2018, regulated rates resulting from the OEB's decision would produce consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period, deferring recovery of about $750 million in OPG nuclear revenues (including interest) to future periods. The OEB is expected to issue the final payment amounts order during the first half of 2018.

The Fair Hydro Trust is forecast to contribute over $500 million in net income over the period, reflecting the spread earned on the equity contributions from the Province to fund 44% of OPG's financing of the Trust. Although the gain on the Lakeview sale is expected to contribute $200 million to net income in 2018, OPG is required to transfer the majority of the proceeds from the sale to the Province. The transfer is included in planned dividend payments to the Shareholder of over $475 million in 2018, which also includes the transfer of the majority of the proceeds from the sale of the 700 University Ave. property in 2017.

**Operations, Maintenance & Administration Costs**

Total plan-over-plan reductions in OM&A expenses from ongoing operations are ~$800 million over the 2018-2021 period, including ~$600 million that contributes to net income and is primarily associated with cost structure, nuclear outage and other business optimization initiatives and other changes that are not subject to true-up with customers through OEB-authorized regulatory deferral and variance accounts. A number of these initiatives are aimed at achieving sustainable productivity enhancements and cost efficiencies through optimization of resources, processes and technology, and will prepare the Company for post-Pickering operations. The initiatives are supported by a continuing corporate culture shift, significant investments in technology, and a clear focus on commercial discipline. While these planned OM&A savings are substantial, they fall short by ~$200 million of fully offsetting the shortfall in OM&A cost recoveries based on the OEB's decision, which negatively affects OPG's ability to achieve the regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021.

The major sources of plan-over-plan OM&A cost reductions not subject to true up with customers are nuclear outage costs, corporate support function costs, operating business unit base OM&A programs, and Renewable Generation project costs. These reductions are underpinned by a lower headcount of ~410 employees, on average in each year plan over plan, reflecting productivity improvements and resourcing strategies aimed at mitigating Pickering closure downsizing costs. The remaining $200 million in plan-over-plan reductions in OM&A expenses from ongoing operations is from lower pension and other post-employment benefit (OPEB) costs, the majority of which will be returned to customers through OEB-authorized regulatory accounts.

**Production**

Higher forecast nuclear generation of 4.4 TWh compared to the previous plan, primarily reflecting outage cycle frequency and other optimization initiatives and equipment reliability improvements at Pickering, and an increase in regulated hydroelectric generation (adjusted for surplus baseload generation (SBG)) contribute ~$475 million in incremental revenue over the term of the plan. The Pickering forced loss rate target is reduced from 5.0% to 3.5% in this plan. The increase in regulated hydroelectric revenue is mainly due to higher operating efficiency, lower assumed market constraints on production and an assumed one-year deferral in the execution of a Sir Adam Beck I GS power canal outage to 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also reflects advancement of the planned Pickering vacuum building outage (VBO) from 2021 into 2020, shifting about 1.5 TWh of generation across the two years and contributing to a plan-over-plan reduction in net income in 2020. OPG continues to assess mitigating actions in light of an extensive nuclear outage program currently planned for 2020 that includes four major planned outages, return to service of Darlington Unit 2 and commencement of Unit 3 refurbishment, in addition to the Pickering VBO.

Main offsetting factors to the plan-over-plan increase in net income include lower regulated revenue and other impacts reflecting the results of the OEB's 2017-2021 rate decision relative to OPG's request, an increase in depreciation expense resulting from capital investments in the accelerated digital transformation strategy and Darlington plant requirements and timing of in-service asset additions, and an updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on updated non-OPG renewable generation cost information published by the Independent Electricity System Operator (IESO).

**Return on Equity and Capital Structure**

Operating ROE increases from 5.3% in 2017 to 8.1% by 2021. These ROE levels are an improvement over the previous plan. Total ROE is forecast to peak at 8.1% in 2018, mainly on account of the gain on the Lakeview sale, and to decline thereafter to 7.1% in 2021. Total ROE will be generally lower than Operating ROE due to returns on the Fair Hydro Trust related equity contributions from the Province being lower than the return on the majority of OPG's operating assets. Owing mainly to the OEB's disallowances of certain requested OM&A costs, the 2018 planned results achieve a Regulated ROE of approximately 7%, below the OEB prescribed return of 8.78% used in setting OPG's regulated rates. Regulated ROE is expected to achieve the OEB-prescribed level by the end of the planning period and averages 8.2% over the 2017-2021 period.

Operating ROE is lower than the Regulated ROE of 8.78% prescribed by the OEB in all years of the plan, reflecting OEB's disallowance of costs as well as OPG's debt ratio remaining below the 55% level reflected in the OEB-approved deemed capital structure. By 2021, OPG's planned debt ratio excluding the Fair Hydro Trust drops to 26%, assuming no capital is deployed on non-organic expansion, such as acquisitions. Management continues to examine the optimization of the Company's capital structure. The business plan is based on an existing capital allocation approach supporting Darlington refurbishment, sustaining capital investment in generating assets and maintaining flexibility to invest in the energy sector. In 2018, OPG will review and formalize a capital allocation policy to guide capital deployment decisions, including a framework for a future dividend policy.

Taking into account planned operating performance and capital investments as well as the implications of the Fair Hydro Trust, forecast credit metrics and operating cash flow levels for the business plan period are expected to continue to support OPG's current investment grade credit rating and cost effective sourcing of funds under the public debt platform. By 2021, OPG's debt is forecast at $5.9 billion, which is largely

consistent with current levels, as operating cash flow inclusive of Fair Hydro Trust returns is sufficient to fund capital expenditures over the period. The Fair Hydro Trust external senior debt is projected to increase to $5.9 billion by 2021.

**Capital Investments and Business Development**

In addition to realigning the cost structure and operating model, OPG's strategy to improve ROE is to expand the business through strategic investments earning commensurate risk-adjusted market rates of return. This strategy will help to optimize the capital structure by gradually reducing equity and increasing debt, while increasing net income. With limited organic development opportunities expected in Ontario, non-organic investments in a portfolio of low-carbon generating assets primarily outside of Ontario as well as potential extensions to OPG's business will be essential to ensuring the Company is able to deliver long-term Shareholder value.

In support of this strategy, the plan allocates incremental capital funding of ~$200 million for potential organic business development investments over the 2018-2021 period, including expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and investments in other innovative technologies that would leverage OPG's core competencies. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the plan term through increased leverage. OPG recognizes that the amount and timing of non-organic investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to the non-organic element of its strategy.

Total capital expenditures over the planning period are ~$570 million higher compared to the previous plan. In addition to the incremental $200 million to fund organic business expansion opportunities, this includes ~$120 million in additional investment to support industry-leading performance at Darlington post refurbishment and ~$40 million of incremental investment in OPG's accelerated digital transformation strategy to enable productivity improvement and modernize information technology infrastructure. Darlington refurbishment expenditures inclusive of a revised cost estimate for the Heavy Water Storage and Drum Handling Facility (D2O Project) increase by ~$105 million compared to last year's plan due to timing of expenditures, with total cost flows through Unit 2 return to service remaining consistent with Board-approved levels. The D2O Project is expected to be completed within the funds previously released to the Darlington refurbishment program.

Planned non-refurbishment capital investments in nuclear regulated assets and information technology are higher than amounts allowed by the OEB in setting regulated rates for 2017 to 2021. In setting the nuclear rates, the OEB disallowed certain capital project costs, reduced OPG's forecast of non-refurbishment capital in-service additions included in rate base for the duration of the 2017-2021 rate-setting period, and applied an efficiency stretch factor to further reduce OPG's revenues from in-service additions. Management believes that proceeding with planned capital investments in excess of 2017-2021 rate base amounts is prudent because they will provide long-term value by improving asset performance and enabling operating cost reductions. The remaining undepreciated value of these investments is expected to be included in rate base in the next rate application. In addition, the plan reflects implementation of an enterprise-wide scalable project delivery model and project management system aimed at ensuring consistent delivery of all projects on time and on budget. Together with demonstrated strong performance in delivering on the planned capital program, these enhancements should support improved OEB decision outcomes in the future.

The plan continues to reflect resource levels necessary to support the execution of several current major projects in line with approved project budgets and schedules, including return to service of refurbished Darlington Unit 2 by February 2020 and commencement of Darlington Unit 3 execution immediately thereafter, completion of the Ranney Falls GS redevelopment by 2019, and completion of the Nanticoke solar facility by 2019. These projects are continuing to track on budget and on schedule. Pre-execution expenditures incurred for the refurbishment of Darlington Unit 3, including acquisition of long lead-time materials and components, are $93 million as of December 31, 2017, with a further ~$540 million reflected in the plan over 2018 to February 2020. Planned development, re-development and station upgrade

projects over the business plan period are expected to increase OPG's total renewable generation capacity by 170 MW by 2021, including the Ranney Falls GS and Nanticoke solar facility projects.

The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the proposed low and intermediate level waste deep geologic repository (L&ILW DGR), recognizing the impact of inherent uncertainty in the ultimate outcome of the Environmental Assessment decision on the timing of project construction. During the planning period, OPG will also continue to maintain the Darlington new site preparation licence, and plans to complete the decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021.

The plan reflects an increased and accelerated focus on innovation and technology, both to drive efficiencies in current operations and to build momentum for new business opportunities leveraging disruption in the energy sector. A combination of capital and OM&A funding is included in the plan in areas such as transportation electrification, nuclear innovation, distributed generation technologies, smart grids and other disruptive innovation technologies. These investments will help leverage OPG's clean electricity in support of action on climate change, including positioning OPG as a leader in transportation electrification in Ontario and driving a pan-Canadian nuclear strategy. These investments will also enhance OPG's brand and social licence.

### Social Licence

During the planning period, OPG will focus on building its brand and reinforcing its social licence, with an emphasis on high standards of public trust and transparency, leadership in clean, cost-effective energy generation and innovation, community engagement and Indigenous Relations. OPG will continue to leverage Power with Purpose as the key platform for stakeholder outreach and branding initiatives, and will build on the Company's existing customer engagement activities to more formally incorporate customer engagement into subsequent business plans, as expected by the OEB. OPG will also focus on fostering a diverse, progressive and engaged workforce to enable the Company's future success.

During 2018, OPG will expand the communication of its social licence focus as part of its financial reporting framework, including through external disclosures related to Environment, Sustainability and Governance. Emerging guidance in North America will increase the requirements in this area, bringing public companies in line with more advanced disclosures common in Europe. OPG is well positioned with its virtually emission free generation fleet to move towards a leadership position in this area.

### Labour Considerations

OM&A cost savings, operating cash flow and net income levels ultimately achieved during the planning period as well as the ability to implement longer-term cost structure changes will be impacted by outcomes of collective agreement negotiations with the Power Workers' Union (PWU) and The Society of Energy Professionals during 2018. Collective agreement outcomes, as well as staffing strategies, will impact the ability to mitigate future employee termination and related costs as a result of the end of Pickering commercial operations, estimated between $1 billion and $2 billion. Consistent with previous business plans, a liability for such employee termination costs is not included in the 2018-2021 Business Plan. US GAAP requires employee termination costs to be recognized when the scope, timing and amount of the downsizing program can be reasonably estimated with sufficient detail and would be unlikely to change significantly. The termination costs associated with the Pickering retirement are assumed to meet net income recognition criteria in 2022 at the earliest, and were not included in the setting of 2017-2021 regulated rates.

A discussion of the 2018-2021 Business Plan, organized by each of OPG's four strategic imperatives, is provided below. The detailed financial and headcount information is included in Appendix 3.

## Financial Strength

In line with the Company's commercial mandate, OPG's objective is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth. In pursuing commercial objectives, OPG takes into account the

impact on Ontario electricity customers by continuously seeking further efficiencies in the Company's cost structure.

The business plan is focused on increasing net income and ROE from core operations through improved operational performance of the generating fleet and a number of steps to realign the corporate cost structure and operating model. In turn, OPG's increasingly improving financial performance, cost effective public debt platform and industry experience position the Company well for developing a portfolio of organic and non-organic investment options in low-carbon generating assets and potential extensions to the business complementary to existing operations. Pursuing such investments will position OPG for long-term success, enabling it to deliver long-term Shareholder value and maintain scale in view of the upcoming Pickering retirement.

To facilitate this strategy, OPG will develop a capital allocation policy in 2018 aimed at maintaining OPG's current investment grade credit rating and providing long-term value to the Shareholder. This policy will outline expectations on how the Company's capital will be deployed between its existing asset base and potential expansion opportunities, and develop a framework for a future dividend policy. A balance needs to be struck among these available uses of capital to ensure deployment is targeted in the areas that provide the best path forward for sustained growth and returns in the longer term.

**Regulated Rates**

The plan reflects the impact of the OEB's decision on OPG's 2017-2021 rate application issued on December 28, 2017. On January 17, 2018, OPG filed a proposed payment amounts order with the OEB implementing the decision's findings in a manner that would result in consistent annual increases of 0.4% or $0.65 on a typical residential customer's monthly bill during the 2017 to 2021 period. The plan reflects this proposal.

For the nuclear operations, the OEB determined the level of costs and return on rate base allowed for recovery as part of each year's revenue requirement, net of an accumulating annual efficiency stretch factor of 0.6%. In the payment amounts order submission, OPG included a rate smoothing proposal based on the allowed revenue requirements and production levels, consistent with O. Reg. 53/05 as amended in March 2017. The objective of rate smoothing is to make the total OPG weighted average payment amounts more stable during the Darlington refurbishment and Pickering closure period by adjusting the nuclear regulated rate within the weighted average payment amount calculation. These adjustments to the nuclear rates determine the annual amounts of nuclear revenue to be recorded in a deferral account for recovery in the post-refurbishment period. Amounts deferred under rate smoothing in a given period are recognized by OPG as income of that period, with the deferral account recorded as a regulatory asset on the balance sheet. Under OPG's proposal, the deferral account balance would reach ~$750 million by the end of 2021, inclusive of interest at approximately 4.5% per annum authorized by the OEB pursuant to the regulation. The regulation requires the total accumulated deferred balance to be recovered over a period of up to 10 years beginning at the end of the Darlington refurbishment project.

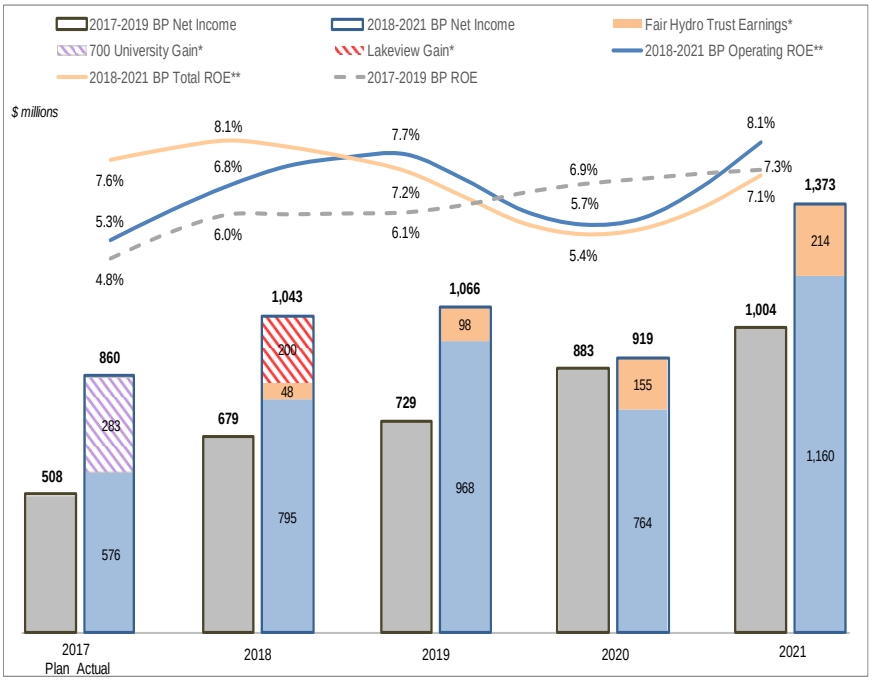
For the hydroelectric operations, the OEB's decision approved an inflation-based formula net of a 0.3% efficiency stretch factor to establish rates for each year. The results of the formula for 2017 and 2018 are known based on inflationary inputs published by the OEB for use in incentive regulation formulas, yielding hydroelectric rate increases of 1.4% in 2017 and 0.9% in 2018. The 2019-2021 hydroelectric rates will be set annually before the beginning of each year based on inputs published by the OEB, and are assumed in the plan to increase by 1.0% in 2019 and 1.5% in each of 2020 and 2021.

Approved regulated rates and rate smoothing deferral amounts for the 2017-2021 period will be determined by the OEB's issuance of the final payment amounts order. OPG expects to start receiving revenue under approved new rates in the first half of 2018. In the payment amounts order submission, OPG has proposed to delay the collection of the retrospective revenue shortfall for the period between the June 1, 2017 effective date of the new rates and their implementation date to the three-year period beginning January 1, 2019, in order to mitigate the impact on customer bills in 2018. The retrospective revenue shortfall will be recorded as income in the period to which the revenue shortfall relates. The revenue shortfall recorded in net income in 2017 is ~$480 million.

Consistent with OEB's expectations, the plan assumes an OEB application in 2018 for clearance of deferral and variance account balances recorded over 2016 and 2017 as well as the balance recorded in the pension and OPEB cash-to-accrual deferral account since November 2014. The regulatory treatment of pension and OPEB costs is discussed under the Operational Excellence section.

**Net Income and Return on Equity**

Net income attributable to the Shareholder is forecast to increase from $860 million in 2017 to $1,373 million in 2021, with Total ROE decreasing from 7.6% to 7.1% as the effect of higher earnings is more than offset by a forecast increase in the equity base reflecting the Province's equity contributions funding 44% of the Fair Hydro Trust financing.




* Net of Tax
** Total ROE = Operating ROE + Fair Hydro Trust Earnings + Gains on sale of the 700 University Ave. property and Lakeview site

Operating net income attributable to the Shareholder increases from $576 million in 2017 to $1,160 million in 2021, as Operating ROE increases from 5.3% in 2017 to 8.1% in 2021. Cumulatively for the 2018-2021 period, forecast operating net income levels are a plan-over-plan improvement of ~$390 million. The improvement in net income and ROE is highly dependent on achieving substantial reductions in OM&A costs and increases in production targeted in the plan, and ability to deliver the Darlington refurbishment on time and on budget.

The major drivers of plan-over-plan changes in 2018-2021 Operating net income are as follows:

- Revenue from higher production at Pickering reflecting lowering of forced loss rate target, outage cycle and other optimization initiatives, and current performance expectations (+$345 million);
- Higher revenue from regulated hydroelectric production primarily due to higher operating efficiency, lower assumed market constraints and an assumed one-year deferral in the start of planned execution of the Sir Adam Beck I GS power canal outage from 2020 to 2021 (+$130 million);
- Company-wide reductions in OM&A costs not subject to true up with customers through OEB-authorized regulatory accounts, as further detailed in the Operational Excellence section (+$600 million);
- Lower interest expense, primarily due to lower OPG borrowing requirements (+$75 million);
- Lower regulated revenue and other impacts reflecting disallowances and other adjustments from the OEB's 2017-2021 rate decision, and updated inputs into the approved hydroelectric incentive regulation rate-setting formula (-$665 million);
- Increases in depreciation expense as a result of investments in the accelerated digital transformation strategy and sustaining nuclear capital projects and timing of in-service asset additions over the period (-$165 million), partly offset by higher capitalized interest (+$40 million);
- Updated forecast of Global Adjustment costs for OPG's electricity grid withdrawals based on non-OPG renewable generation cost information published by the IESO (-$125 million); and
- Net change in income tax expense related to above items (+$130 million).

The planned 2018 Operating net income attributable to the Shareholder of $795 million is an improvement over the results for 2017 of $576 million, with a further improvement to $968 million forecast in 2019. The earnings in 2017 are negatively impacted by a partial-year effective date of June 1, 2017 for new regulated rates, which resulted in forgone net income of ~$325 million. Other factors underpinning the year-over-year increases in 2018 and 2019 include:

- Higher nuclear production in 2017 and 2019 reflecting outage optimization initiatives;
- Lower OM&A expenses in 2019 due to fewer major planned outages at Pickering and cost efficiency improvements;
- Write-off of previously incurred developmental capital expenditures and higher expenses associated with inventory obsolescence costs in 2017;
- Annual regulated hydroelectric rate increases under the incentive regulation formula;
- Year-over-year increases in capitalized interest for the Darlington refurbishment capital expenditures; and
- Earnings from the Nanticoke solar facility upon completion in 2019.
- The year-over-year favourable factors in 2018 are partially offset by higher depreciation expense in 2018 as a result of increased investments in the accelerated digital transformation strategy and timing of in-service asset additions, and higher detritiation services revenue in 2017 reflecting increased demand and stronger performance of the Tritium Removal Facility.

Operating net income attributable to the Shareholder is forecast to temporarily decrease to $764 million in 2020, with Operating ROE declining to 5.7%, mainly due to a larger planned outage program at Pickering, including advancement of the six-unit VBO from 2021, that significantly decreases production and increases OM&A expenses. Other factors impacting the year-over-year Operating net income change in 2020 include:

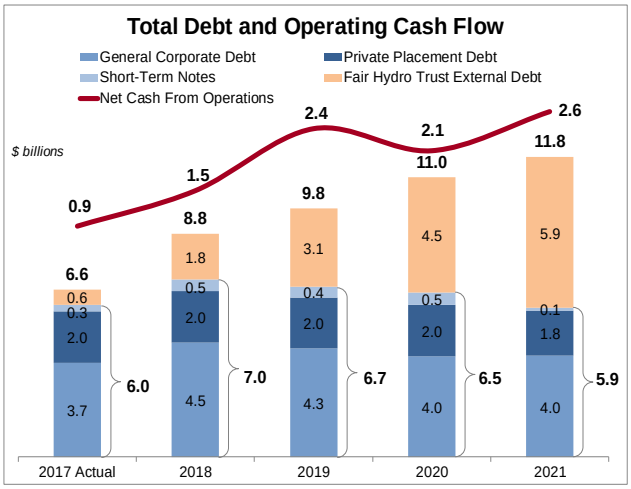
- Lower hydroelectric production due to the planned forebay and crossover canal outage at the Sir Adam Beck I GS in 2020;
- Lower capitalized interest for the Darlington refurbishment capital expenditures as the first refurbished unit returns to service in February 2020; and
- Expiry of the Thunder Bay biomass energy supply agreement in January 2020.
- These factors are partially offset by the impact of the first refurbished Darlington unit entering rate base and regulated hydroelectric rate increases under the incentive regulation formula.

Planned Operating net income attributable to the Shareholder increases to $1,160 million in 2021, compared to 2020, reflecting an increase in nuclear production and lower outage OM&A expenses due to multiple planned outages at Pickering in 2020, no major planned outages at Darlington in 2021 and continued efficiency improvements, and higher capitalized interest for the Darlington refurbishment capital expenditures. These factors are partially offset by the impact of lower regulated hydroelectric generation in 2021.

Net income contribution from the Fair Hydro Trust increases from $48 million in 2018 to $214 million in 2021, predominantly on account of the spread earned on the Province's equity injections into OPG to fund 44% of the Trust financing requirement. The net income contribution from the Trust is net of interest costs on OPG's debt to fund 5% of the Trust financing requirement. OPG's management fees represent a small fraction of the Trust's net income contribution and range from $1 million to $9 million annually between 2017 and 2021, before taxes.

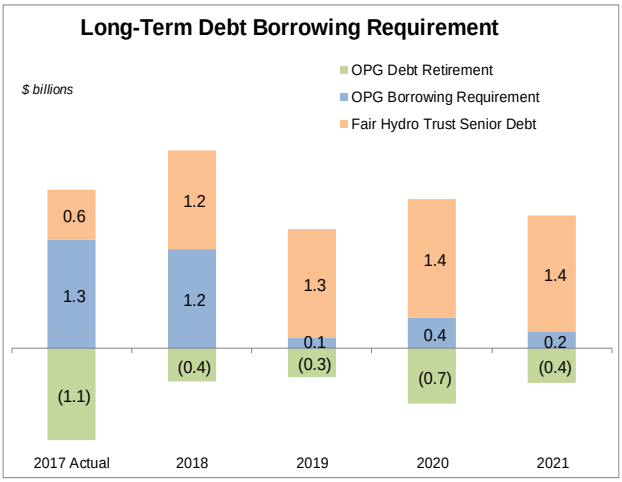
The plan includes a forecast after-tax gain of $200 million on the Lakeview sale in 2018, which temporarily increases Total ROE to 8.1% in 2018. The sale was not included in the previous plan.

## Financing and Liquidity




Forecast operating cash flow, inclusive of Fair Hydro Trust impacts, increases from $0.9 billion in 2017 to $2.6 billion in 2021. The increase in 2018 over 2017 is due to the implementation of regulated rate increases in 2018, partially offset by lower nuclear production in 2018. The increase in 2019 is due to higher nuclear production, lower OM&A costs, assumed commencement of collection of retrospective revenue for the period between June 1, 2017 and the implementation date of new regulated rates in 2018, and rate riders assumed to result from the 2018 deferral and variance account application to the OEB. A ~5 TWh decline in nuclear production in 2020, compared to 2019, and higher nuclear outage OM&A costs result in a year-over-year decrease in operating cash flow. Higher operating cash flow in 2021 is mainly due to a year-over-year increase in nuclear production and decrease in OM&A costs. The Fair Hydro Trust contribution to operating cash flow grows over the period commensurate with increased earnings from the Trust.

In aggregate, operating cash flow inclusive of Fair Hydro Trust impact is sufficient to fund capital expenditures over the planning period, with OPG's total debt (i.e. excluding the Fair Hydro Trust external senior debt) forecast to decrease from $6.0 billion in 2017 to $5.9 billion in 2021. This assumes no capital is deployed on non-organic expansion such as acquisitions. The assumed effective interest rate for new general corporate debt during the planning period is an average of 5.0%. OPG's sources of general corporate debt include credit facilities with the Ontario Electricity Financial Corporation and the public debt platform. The Fair Hydro Trust external senior debt is forecast to increase to $5.9 billion by 2021, based on forecast cumulative investment interest acquired of $11.8 billion. The assumed effective interest rate for new Fair Hydro Trust external senior debt over the planning period is 4.25%, on average.

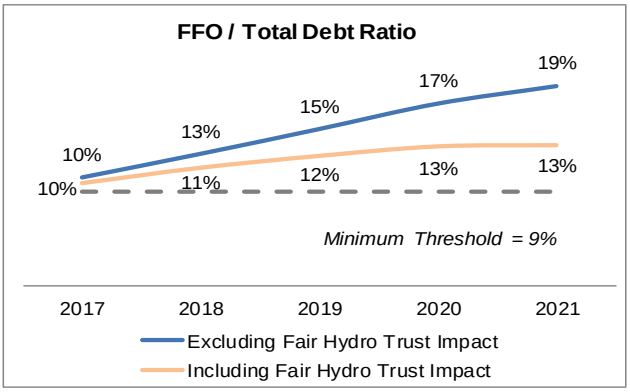


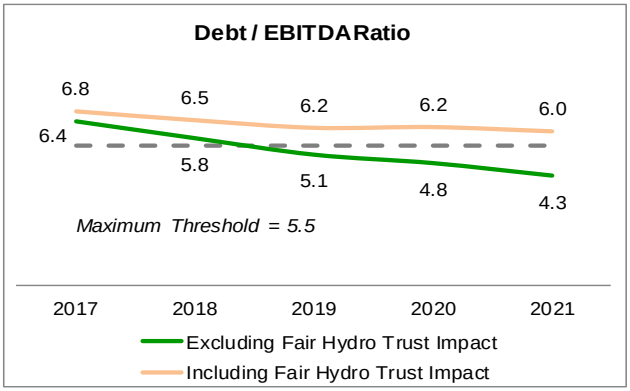

OPG's debt ratio excluding the Fair Hydro Trust external senior debt is forecast to decline from 36% in 2018 to 26% in 2021, absent any major non-organic growth investments. This is below the 55% level reflected in the OEB deemed capital structure used to set regulated rates, which results in a lower value of the Shareholder's investment in the Company. In setting OPG's 2017-2021 regulated rates, the OEB rejected OPG's request to decrease the debt portion of the deemed capital structure from 55% to 51% and increase the equity portion from 45% to 49%. A higher debt portion of the deemed capital structure contributes to lower regulated revenues. Management continues to examine the optimization of the Company's corporate capital structure and approach to capital allocation.

OPG's strategy to expand its business portfolio through organic development and non-organic investments will help to optimize the corporate capital structure by increasing net income while gradually reducing equity and increasing debt. Although non-organic investments are not specifically assumed in the plan, OPG forecasts that up to $3 billion would be available for such investments over the business plan term through increased leverage. OPG recognizes that the amount and timing of external investments will depend on market opportunities and Shareholder's expectations, and will take into account the need for continued excellence in core operations and Darlington refurbishment execution and the need to maintain OPG's credit metrics. Based on these factors, OPG would take a measured, paced approach to external investments.

## Credit Metrics

Maintaining an investment grade credit rating is critical to OPG's continued ability to access cost effective financing. To support this objective, OPG monitors the Funds From Operations (FFO) to Total Debt ratio and the Debt to Earnings Before Interest, Taxes and Depreciation and Amortization (EBITDA) ratio, which are the core measures used in Standard & Poor's credit rating methodology. Total Debt, as defined by Standard & Poor's, includes pension and OPEB liabilities. The forecast credit metrics and forecast operating cash flow levels for the planning period are expected to continue to support OPG's current investment grade credit rating.



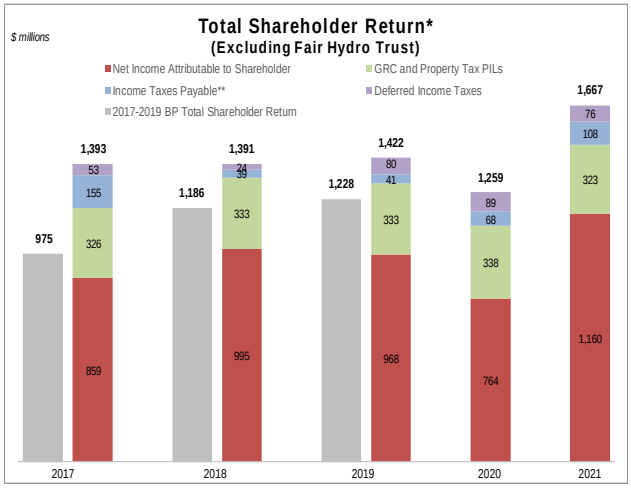

The FFO/Total Debt ratio, both with and without the impact of the Fair Hydro Trust, will remain within threshold over the planning period. The ratio without the Fair Hydro Trust improves steadily over the 2017 to 2021 period as FFO increases. FFO increases in 2018 due to the full-year impact of new regulated rates compared to seven months in 2017, in 2019 due to higher nuclear production and commencement of rate riders for recovery of deferral variance accounts, in 2020 due to an increase in revenue from the return to service of Darlington Unit 2, and in 2021 due to higher nuclear production and lower OM&A costs. With the Fair Hydro Trust, the ratio is somewhat lower and more stable than without the Fair Hydro Trust, as a result of the Trust's external senior debt, partially offset by incremental income from the spread earned on the Province's equity injections.

Excluding the impact of the Fair Hydro Trust, the Debt/EBITDA ratio is at or below the threshold during the business plan term. As EBITDA increases over the business plan term, the ratio improves. The upward trend in EBITDA is consistent with the drivers of increasing FFO. As anticipated, when the impact of the Fair Hydro Trust is included, the Debt/EBITDA ratio exceeds the threshold in all years of the plan, largely due to the Trust's external senior debt.

## Delivering Shareholder Value

OPG's Total Shareholder Return consists of net income, income taxes, hydroelectric gross revenue charge payments, and payments in lieu (PILs) of property taxes to the OEFC. OPG plans to contribute $5.7 billion in Total Shareholder Return over the 2018-2021 period, not including the impact of the Fair Hydro Trust. Total Shareholder Return on OPG's fiscal basis is projected to increase over the period as net income increases.

Over the 2017-2019 period, OPG expects to contribute $4.2 billion in Total Shareholder Return not including the impact of the Fair Hydro Trust, which represents an increase of ~$800 million over the 2017-2019 commitments made to the Province based on the previous plan, primarily due to higher net income across all three years.




* On OPG's fiscal basis
** Includes income tax PILs and amounts recoverable from, or payable to ratepayers

The Fair Hydro Trust is forecast to contribute an additional $685 million to the Province, predominantly through the spread earned on the Province's equity injection to fund 44% of the Trust's financing.

In 2017, OPG received proceeds from the sale of OPG's 700 University Ave. property. The forecast for 2018 includes proceeds from the sale of the Lakeview site. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions. Both of these properties are non-core assets of OPG's unregulated business.

## Operational Excellence

The plan recognizes that strong core operational and cost performance is foundational to OPG's continued success and longer term strategy. Continuous improvement in performance is expected by the Shareholder, customers and the OEB. In addition to directly affecting output and cost levels, operational and cost performance is a critical driver of rate application outcomes. Benchmarking is a key tool used by the OEB to assess regulated assets' performance as part of rate applications, including as the basis for determining efficiency stretch factors for nuclear and regulated hydroelectric businesses. Continuous improvement in performance and associated benchmarking should support more favourable outcomes of future OEB decisions.

OPG remains focused on improving asset reliability, increasing output and safely generating electricity at a low cost, with performance targets over the planning period set to drive excellence in these areas. The plan builds on OPG's improved performance in a number of areas in 2017, seeking to maximize the value of existing assets and further improve fleet performance during a period of relative regulatory certainty provided by the OEB's 2017-2021 rate decision. This includes implementing initiatives aimed at maximizing generation revenue and improving reliability performance at Pickering based on continued operations to 2024, positioning Darlington for industry-leading operational and cost performance post refurbishment, and maintaining and improving strong reliability and cost effectiveness of the hydroelectric fleet. These initiatives complement an enterprise-wide set of initiatives to improve productivity and realign the Company's cost structure and operating model, discussed under the Operations, Maintenance & Administration Expenses section. In driving these improvements, OPG remains committed to achieving the highest standards of workplace and public safety across its operations and will continue to invest in maintaining and enhancing the safety and security of its generating facilities.

### Nuclear Operations

OPG is focused on improving reliability performance and increasing output from the nuclear fleet. This includes initiatives aimed at executing optimized planned outages along with improving equipment reliability, implementing integrated asset management planning, and enhancing maintenance programs. A key driver of improved equipment reliability and station performance is the development and implementation of the Monitoring and Diagnostic Centre. The Centre will facilitate collection and analysis of data to improve early detection of equipment degradation, reduce unplanned maintenance and optimize performance of major components. Improved station performance also will be supported by a greater focus on asset management planning aimed at early identification of project requirements and development of an optimized investment strategy. Maintenance and outage programs over the planning period will continue to focus on improved work planning, preparation and execution.

These and other initiatives will support a reduction to Pickering's forced loss rate target to 3.5% from 5.0% starting in 2018 as well as achievement of Darlington's top-quartile forced loss rate target of 1.0%. A temporarily higher forced loss rate is assumed for Darlington Unit 2 upon return to service following refurbishment, based on industry experience. OPG will continue to target top-quartile forced loss rate performance for the station as refurbished units achieve steady-state operations post refurbishment.

OPG benchmarks the costs of the Pickering and Darlington stations against other nuclear stations using indicators that measure performance on a per MWh basis. With a combination of the smaller size Pickering units relative to the majority of industry peers and impacts of moving through refurbishment of the Darlington units, the benchmarking of units on a per MWh basis will continue to pose some challenges in light of the OEB's 2017-2021 regulated rate decision that emphasized benchmarking results. As discussed further in the Operations, Maintenance & Administration Expenses section, the OEB used benchmarking to support a more aggressive efficiency stretch factor in setting OPG's 2017-2021 nuclear regulated rates. In

order to achieve an appropriate rate of return and position itself for more favourable future rate application outcomes, OPG will seek to implement commensurate productivity improvements and maximize production output over the business plan period.

Although Pickering is expected to continue to benchmark in the fourth quartile for unit energy cost due to its smaller unit size, the station's 2017 actual results and forward targets demonstrate an improvement of ~$10/MWh in the Total Generating Cost (TGC) measure, on average, compared to the previous plan. As anticipated, Darlington's cost performance continues to be temporarily impacted by higher project costs associated with asset life cycle and plant life extension work and increased outage costs to address the aging management program, with resulting third quartile target performance over the 2018-2020 period expected to improve to the second quartile by 2021. On a per unit basis, OPG's all-in operating and capital expenditures for the nuclear stations continue to be amongst the lowest in the industry. In addition to Pickering's forced loss rate performance, plan-over-plan improvement is observed at both stations in several operational targets including All Injury Rate, Collective Radiation Exposure, and On-line Corrective Maintenance Backlogs. The operational targets for the Nuclear business unit are further detailed in Appendix 4.

**Hydroelectric Operations**

OPG continues to focus on increasing the utilization of existing hydroelectric assets through increases in energy output and, where economic, increases in capacity, as well as identifying opportunities for cost efficiencies in line with the incentive regulation model. Operational performance initiatives over the business planning period will aim to increase water to wire efficiency, improve operational flexibility and optimize outage planning to maximize availability and returns during high demand periods, subject to water conditions. The forecast fleet-wide availability for hydroelectric assets averages 87% during the business plan period, with a target equivalent forced outage rate of 1.8% on average. The availability of the contracted hydroelectric assets is projected to reach 92% by 2021 as major work including overhauls, upgrades and sluicegate replacements at the Lower Mattagami stations is completed. The availability of the regulated hydroelectric assets temporarily declines from an average of 88% over the 2018-2021 period to 85% in 2021 reflecting a Sir Adam Beck I GS power canal outage assumed in the summer of 2021. OPG will add approximately 170 MW of incremental capacity to its renewable generation fleet over the plan term, including through completion of the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 and 2, runner upgrade program and other value enhancing projects.

OPG is pursuing innovation and technology-based improvements in asset management and equipment maintenance strategies in order to reduce costs and increase reliability of the hydroelectric stations. This includes expanding the Monitoring and Diagnostic Centre concept beyond nuclear operations and transitioning to digital work management. Objectives of the Monitoring and Diagnostic Centre for Renewable Generation operations include developing a common data historian and a data architecture strategy that will optimize asset management, facilitate a move from preventative maintenance to condition-based maintenance and reduce forced outage costs through predictive failure modelling capability. In addition to improving work flow efficiency, digital work management is expected to improve staff engagement in line with OPG's cultural shift.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 out of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94% of the energy delivered from the regulated hydroelectric fleet. Eighteen out of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for availability. The operational and cost improvement initiatives identified in the plan will help support OPG's hydroelectric benchmarking standing. An integrated strategy is being developed in 2018 to assess hydroelectric benchmarking performance, taking into account incentive regulation implications. The operational targets for the Renewable Generation business unit are further detailed in Appendix 5.

Key enterprise level and business unit initiatives that will support achievement of strategic objectives and business plan goals are detailed in Appendix 6.

**Safety**

OPG is committed to high standards of public and workplace safety and will continue to operate all of its facilities in a safe, secure and reliable manner, while making investments to maintain and enhance the safety of its generating assets. This includes continuing to operate with nuclear safety and waterways safety as overriding priorities by maintaining a strong focus on nuclear safety programs, continuing to invest in nuclear safety systems and dam and other waterway safety upgrades, and further strengthening public awareness regarding water safety.

In the past five years, as a result of lessons learned from the Fukushima accident, OPG has strengthened the nuclear safety program at its stations by installing multiple portable emergency mitigating equipment units, enhancing emergency preparedness and response capability, and improving protocols and procedures in response to potential adverse events. Probabilistic safety assessment results have confirmed that these initiatives have further strengthened the safety of OPG's nuclear plants. Through its annual evaluation of the safety performance of Canada's nuclear plants, the CNSC has concluded that both Pickering and Darlington operate at the highest level of nuclear safety.

OPG continues to demonstrate strong industry leadership with its hydroelectric Dam and Public Safety Program, which encompasses public safety and emergency management over the Company's 241 dams and 66 hydroelectric facilities. The program is considered to be international best practice in a number of areas. During the planning period, OPG will continue to make investments in dam safety, with planned project work at hydroelectric sites totalling ~$120 million over period, in addition to the $300 million Little Long Dam Safety project discussed under the Project Excellence section. OPG will also continue to maintain a strong water safety education and outreach program.

OPG has consistently achieved top quartile workplace safety performance compared to the Canadian Electricity Association benchmark and although it did not meet the internal target, 2017 safety performance was the third-best year in the Company's history. OPG will continue to set aggressive but achievable internal targets to drive continuous improvement in safety performance. Achievement of safety goals will be supported through continued branding and integration of the "iCare Enough to Act" initiative aimed at renewing employees' personal commitment to safety, strengthening of an enterprise wide "values-based" safety culture through peer coaching, information sharing and work planning, and a focus on the use of human performance tools such as increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

Additionally, business unit specific initiatives are being implemented to target improved safety performance over the planning period. Renewable Generation will execute on a broad-based safety improvement plan targeting significant cultural and work program improvements in the safety management system. Objectives include strengthening proactive reporting, enhancing linkage of the embedded health and safety advisors with local senior management, modifying human performance practices based on internal and external benchmarking and reinforcing a culture of personal leadership in safety. In the Nuclear organization, safety programs are being implemented to re-energize the safety culture through communication, recognition, human performance coaching and risk management. Leveraging consistent best quartile performance at both Pickering and Darlington, business plan targets for safety at the nuclear stations have been set to drive further improvement over the previous plan, toward the ultimate goal of zero injuries.

**Environment**

OPG remains committed to meeting its environmental compliance obligations, including any commitments it makes, with the objective of surpassing these compliance obligations where it makes business sense. In keeping with the business plan, OPG will continue to manage its operations to minimize environmental risks and seek opportunities for environmental leadership. OPG's priorities over the planning period include keeping radiological emissions as low as reasonably achievable, preventing significant environmental events, and implementing a transportation electrification strategy discussed in the Social Licence section as well as initiatives to enhance biodiversity.

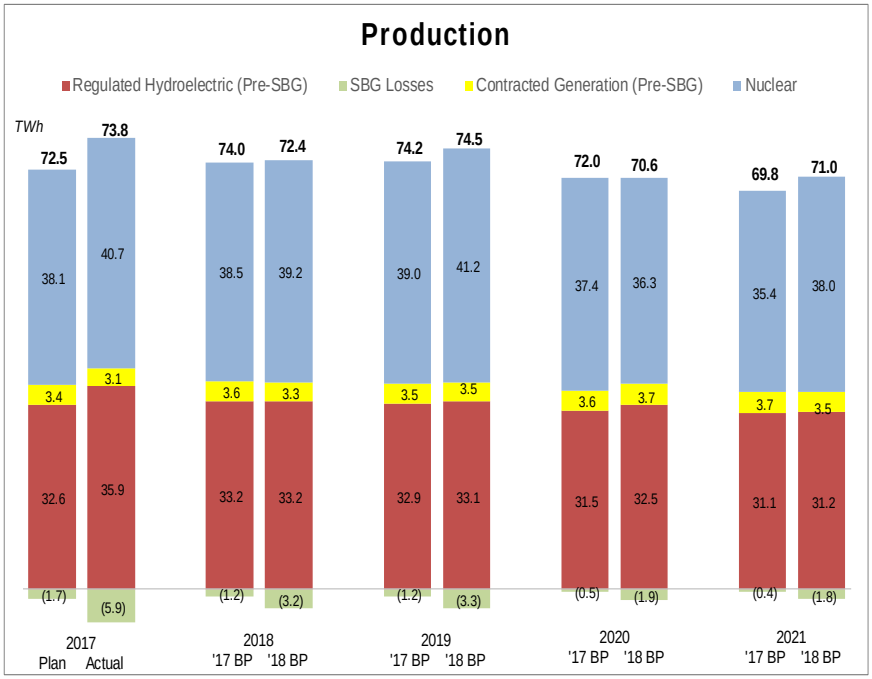
In 2017, OPG met or outperformed its targets for spills, environmental infractions, carbon-14 emissions to air and radioactive waste, with no significant environmental events. Performance for tritium emissions to

air and water during 2017 remained less than one percent of the regulatory limit. The Company will pursue further improvement in environmental performance through setting of more stringent targets in this plan, including in the area of spills and infractions for Renewable Generation and radioactive waste, infractions and tritium emissions for the nuclear operations.

To maximize the benefits of its biodiversity initiatives, OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, risks and proposed actions. In 2017, OPG's continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species were recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement. OPG will continue to advance its biodiversity efforts during the business plan period.

**Production**

Total planned OPG production net of SBG impacts is 288.5 TWh over the period. Adjusted for SBG impacts, total planned production is 298.7 TWh, which is 5.4 TWh higher than in the previous plan.




The plan-over-plan increase is primarily driven by higher nuclear production of 4.4 TWh, mainly at Pickering. The increase in Pickering production includes lowering of the forced loss rate from 5.0% to 3.5% (1.4 TWh increase) reflecting reliability improvements and current performance expectations, outage frequency optimization through transition from a 24-month to 30-month outage cycle (1.6 TWh increase) and outage scope and duration optimization initiatives (1.4 TWh increase). The changes in outage frequency include the deferral of a Pickering Unit 6 planned outage from the fall of 2017 to 2018, a major driver of the year-over-year decrease in nuclear production in 2018, and result in fewer major planned outages at Pickering in 2019.

The Pickering production plan includes advancement of the Pickering VBO to 2020 from 2021, consistent with current CNSC license requirements, which reduces generation by 1.5 TWh in 2020, with a corresponding increase in 2021. The Pickering VBO is assumed to require a 30-day outage for all six operating units at the station.

The Darlington production plan is virtually unchanged from the previous business plan, including an assumed temporary increase in the forced loss rate and number of planned outage days as the first refurbished unit returns to service in early 2020 and a partial overlap of the second and third unit refurbishments in 2021. No major outages are scheduled at Darlington in 2021 as two units undergo refurbishment.

With the return to service of Darlington Unit 2, the start of Darlington Unit 3 refurbishment, the Pickering VBO and four major planned outages across both plants, the 2020 nuclear outage program is extensive and complex. OPG continues to assess mitigating actions taking into account the impact on resources and execution capability, while ensuring that regulatory and other work program requirements continue to be met and support improved station performance.

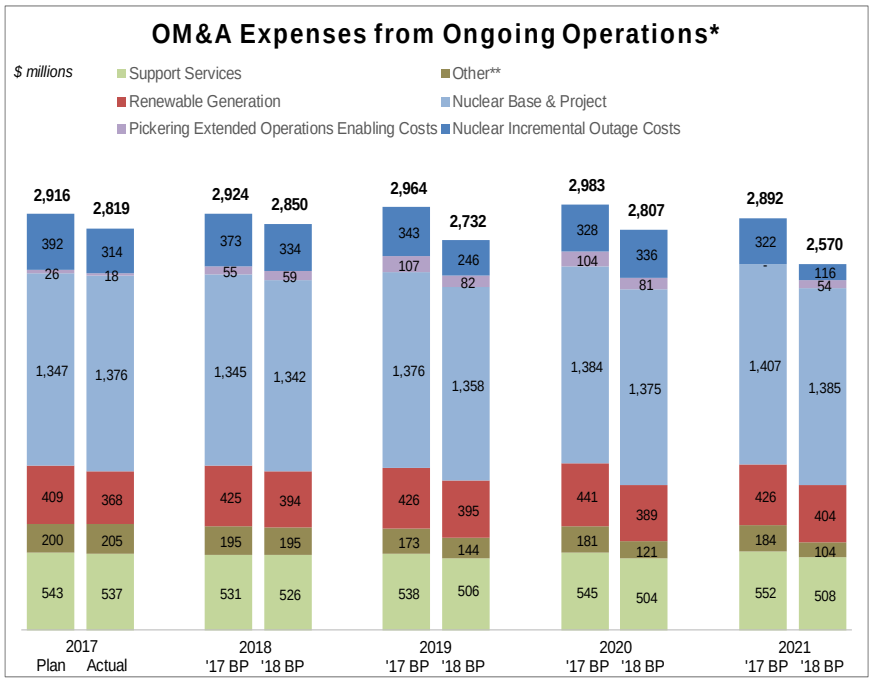
The hydroelectric production plan reflects a return to median water flows following extremely high water flows and resulting SBG conditions in 2017. SBG-adjusted regulated hydroelectric and contracted fleet production over the business plan term is 1.0 TWh higher compared to the previous plan, primarily due to an assumed one-year deferral of a Sir Adam Beck I GS power canal rehabilitation outage from the summer of 2020 to the summer of 2021. The outage reduces hydroelectric production by ~1.2 TWh in 2021. OPG will continue to optimize major project work sequencing in Renewable Generation, with the final timing of the power canal outages being determined as part of the planning phase of the project. The plan also continues to reflect a series of outages at the Sir Adam Beck units to accommodate Hydro One's planned work in the Beck switchyard over the planning period, and an outage at the Sir Adam Beck I GS in 2020 for work to rehabilitate the forebay and crossover canal. Planned contracted fleet production peaks in 2020 due to increased production at the Lennox GS reflecting anticipated increased operation to support IESO system reliability requirements.

SBG conditions are projected to result in forgone hydroelectric production of 10.2 TWh during the 2018-2021 period, an increase of 6.9 TWh compared to the previous plan, primarily as a result of an updated, lower OPG forecast of Ontario grid demand. SBG conditions are expected to be lower in 2020 and 2021 than in earlier years owing mainly to lower OPG nuclear production and commencement of Bruce unit refurbishments.

OPG's three wholly-owned thermal stations with a total capacity of close to 2,500 MW will continue to provide the electricity system with the flexibility to meet system demand and capacity requirements during the business plan term under their respective energy supply agreements. The current Thunder Bay biomass energy supply agreement expires in January 2020, with agreements for Lennox and Atikokan stations expiring within several years of the business plan period. These assets are unique in their operational flexibility and in the world-leading biomass innovation. The economics of these assets post existing contracts may be impacted by structural changes to Ontario's electricity market being contemplated through the IESO Market Renewal Program. OPG continues to be an active participant in the IESO's Market Renewal engagement process to ensure that the impacts of a redesigned electricity market are understood, the unique flexibility of OPG's assets is appropriately valued and the Company's operations are optimized under the new market rules.

**Operations, Maintenance & Administration Expenses**

The plan is targeting reductions of ~$600 million in OM&A expenses from ongoing operations over the 2018-2021 period compared to the previous plan, excluding ~$200 million in lower pension and OPEB costs the majority of which are subject to true up with customers through OEB-authorized deferral and variance accounts. These reductions reflect steps being taken to improve efficiency and align OPG's organizational structure and operating model with post-Pickering operations. The reductions of ~$600 million will be primarily enabled through optimization of resources, processes and technology and other business optimization initiatives across the organization, including nuclear outage optimization. Business optimization and organizational design work is currently underway as part of the OPG25 strategic initiative




* Excludes Darlington refurbishment OM&A expenses and all OEB variance and deferrral account offsets

** Includes centrally held pension / OPEB costs, insurance and other corporate level costs

to identify opportunities for reductions in operating costs, mainly in corporate Support Services and nuclear base OM&A programs. In addition to delivering improved financial results through increased net income during the business plan term and supporting more favourable outcomes of future OEB decisions, these changes will benefit customers by helping to position Darlington for industry-leading performance post refurbishment, further improve the cost effectiveness of the hydroelectric fleet and mitigate the Pickering closure downsizing costs. The major sources of cost reductions reflected in the plan are nuclear outage costs (~$255 million), Support Services costs (~$125 million), Nuclear base OM&A programs (~$85 million), Renewable Generation base OM&A programs (~$60 million) and Renewable Generation project costs (~$75 million).

The plan's cost reduction targets recognize that OPG's regulated rates for the business plan term have been set under an incentive based regulation methodology that is informed by the OEB's Renewed Regulatory Framework (RRF). Achieving operational effectiveness through meaningful efficiency incentives is a main focus of the RRF. In setting incentive regulation rates for OPG, the OEB applied efficiency stretch factors that reduced OPG's recoverable OM&A costs by an increasing amount each year over the business plan term, in addition to disallowing recovery of certain OM&A costs. Taking into account these adjustments, OM&A cost levels allowed by the OEB are ~$800 million lower than the OM&A cost levels reflected in the previous business plan. Therefore, while the plan-over-plan cost reductions of ~$600 million committed in this business plan are substantial, they do not fully offset, by ~$200 million, the shortfall in OM&A cost recoveries based on the OEB's decision. This negatively impacts OPG's ability to achieve the Regulated ROE target. Future business plans are expected to target additional cost improvement opportunities to close this gap by 2021. The OEB used OPG's external benchmarking of OPG's regulated operations' historical operational and cost performance to support the majority of cost reductions applied in setting the regulated rates. Benchmarking results are expected to continue to form a material part of OEB's assessment of OPG's cost levels in future rate applications.

Compared to the previous plan, the major changes to OM&A expenses from ongoing operations for the 2018-2021 period are as follows:

- Reductions in nuclear outage costs reflecting outage frequency optimization at Pickering, in addition to ~$45 million in savings realized in 2017 (-$140 million);
- Reductions in nuclear outage costs reflecting outage scope, duration and vendor scheduling optimization savings at Pickering and Darlington (-$115 million);
- Savings in Nuclear base OM&A costs from lower nuclear staffing levels reflecting strategies to leverage attrition and increase resource flexibility, optimization of operator training, and maintenance and other work program efficiencies (-$120 million), partially offset by higher materials requirements for the stations based on current experience compared to plan (+$35 million);
- Savings in Renewable Generation base OM&A costs, including from regionalization initiatives such as the integration of Central Operations, control room consolidation, and work management and organizational realignment efficiencies (-$60 million);
- Savings in corporate Support Services costs reflecting business optimization initiatives and organizational changes in support of the OPG25 initiative (-$125 million), including the following:
    - Reductions in Real Estate and Supply Chain costs from advancement of OPG's planned lease exit strategy, facilities staffing and maintenance efficiencies and automation, and organizational redesign initiatives;
    - Lower People & Culture function costs reflecting a decrease in staffing levels and other costs, including simplifying human resource support processes, leveraging digital solutions and streamlining training qualifications;
    - Lower Finance costs reflecting amalgamation of functions and other organizational design initiatives, rationalization of processes, and implementation of a corporate-wide shared services model. The corporate-wide shared services model is expected to be expanded to other shared services functions currently performed throughout the Company; and
    - Savings in Chief Information Office costs reflecting redesign of functions and processes including greater emphasis on automation, robotic processing and enhanced self-serve capability, software cost optimization, and digitization and other cost elimination initiatives.

    - These reductions are partially offset by an increase in project costs in 2018 in support of the digital transformation strategy and incremental costs over the planning period in support of the transportation electrification strategy.
- Changes in timing and accounting classification of certain planned Renewable Generation projects reflecting portfolio re-prioritization and more advanced scope definition (-$75 million); and
- Lower insurance costs reflecting savings achieved in the nuclear liability insurance program (-$25 million) and elimination of the annual fee for the Province's financial guarantee to the CNSC due to the fully funded status of the nuclear segregated funds (-$15 million).

In addition to varied levels of Pickering extended operations enabling costs that have been reflowed from the previous plan in line with the revised outage schedule, year-over-year changes in OM&A expenses from ongoing operations over the 2018-2021 period include:

- Variability in nuclear outage costs reflecting timing of planned outages, including fewer planned outages at Pickering in 2019 and 2021 under the optimized outage cycle, the Pickering VBO in 2020 and no major planned outages at Darlington in 2021. The movement of the Pickering VBO from 2021 in the previous plan shifted ~$40 million in OM&A costs to 2020 in this plan;
- Reductions in staffing levels and other cost drivers reflecting continued focus on productivity improvement and business optimization initiatives, net of assumed labour escalation and other inflationary impacts;
- Write-off of previously incurred development capital expenditures and higher expenses associated with nuclear inventory obsolescence costs in 2017; and
- Higher nuclear base OM&A costs of ~$15 million in 2019 related to the CNSC's Fitness for Duty program, compared to 2018. Consistent with the previous plan, total program costs over the planning period are estimated at ~$40 million.

The Darlington Refurbishment project expenses vary over the planning period with the expected timing of pressure tube and feeder removal activities and other work programs not eligible for capitalization.

The regulatory variance and deferral account impacts to OM&A expenses increase to 2020 due to lower pension and OPEB costs and then decline in 2021 reflecting timing changes in Pickering extended operations enabling costs compared to the OEB-approved levels.

**Pension and OPEB Costs**

Lower pension and OPEB costs compared to the previous plan are due to higher discount rates, better than expected pension asset performance, lower headcount and updated actuarial inputs. As in the previous plan, projected pension and OPEB costs are decreasing year over year during the planning period, mainly reflecting projected pension asset returns and lower amortization of net historical actuarial losses. The regulated business portion of the plan-over-plan and year-over-year changes in pension and OPEB costs is offset by corresponding changes in the cash-to-accrual deferral account, discussed below.

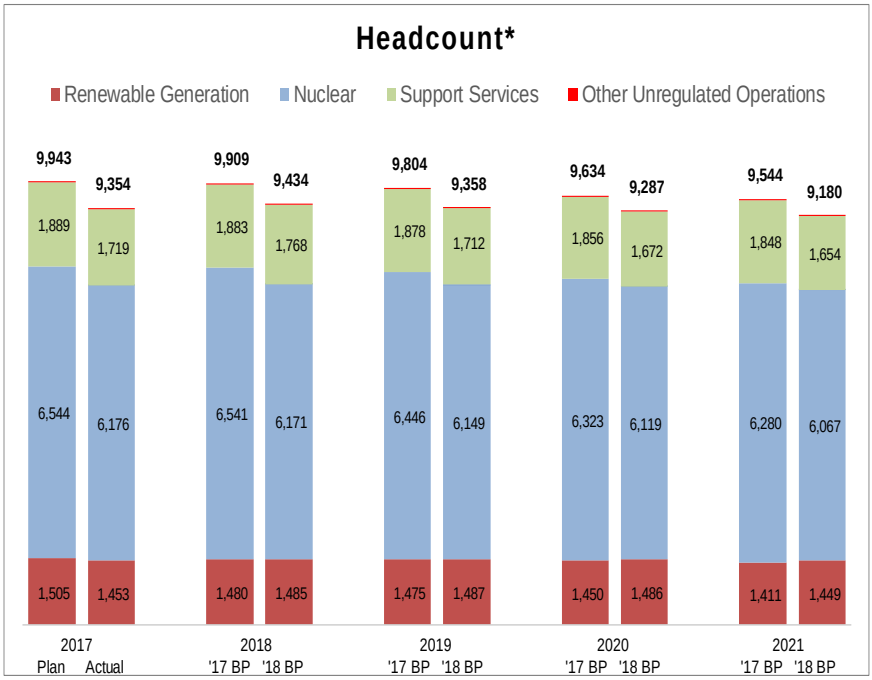
The 2017-2021 regulated rates limit the recovery of OPG's pension and OPEB costs to cash amounts, with the difference between accrual and cash amounts continuing to be recorded in an OEB authorized deferral account in place since 2014. In 2017, the OEB issued its final report on the regulatory treatment of pension and OPEB costs, establishing the accrual basis of accounting as the default rate-setting method for regulated utilities in Ontario. As required by the report, OPG will seek the OEB's approval to resume the accrual basis of recovery and begin to collect the balance accumulated in the deferral account, through a deferral and variance account application planned later in 2018. OPG must begin to collect the account balance by November 2019 in order to avoid writing off a portion of the balance against net income as would be required by US GAAP. The deferral account balance stood at ~$600 million at the end of 2017.

**Headcount**

Significant staffing reductions are being realized across the organization, compared to the previous plan, as part of efforts to realign the corporate cost structure and drive productivity improvement and operational efficiencies. These ongoing efforts will support the OPG25 initiative in implementing operating model and

organizational design strategies to ensure cost effectiveness of post-Pickering operations, and will help to mitigate downsizing costs related to the Pickering closure.

Actual year-end 2017 headcount was ~590 lower than expected in the previous plan, with ~370 fewer employees in the Nuclear organization, ~170 fewer employees in Support Services organizations and ~50 fewer employees in Renewable Generation. This overall trend continues over the 2018-2021 period as forecast headcount is lower by ~410 employees, on average, in each year. Nuclear organization headcount includes employees working on the Darlington refurbishment.




* 2017-2019 BP and 2017 Actuals have been restated for 2018 organizational changes. Includes PWU Term employees.

Nuclear headcount is lower by ~270 employees on average over the period, compared to the previous plan. The reduction leverages attrition opportunities and a move towards a more flexible staffing strategy to fulfil short-term operating needs while considering long-term staffing goals in support of the OPG25 initiative. Headcount for Support Services organizations decreases by ~165 on average over the period, compared to the previous plan. The decrease includes ~95 employees in Finance, ~35 employees in People & Culture and ~35 employees in Chief Administrative Office and is expected to be achieved through work elimination, technology advances and organizational redesign. Renewable Generation headcount increases by ~20 employees on average, compared to the previous plan, primarily adding staff in support of project planning, management and execution.

Notwithstanding plan-over-plan reductions, high levels of attrition reflecting employee demographics and a commitment to increase work execution will necessitate some replacement hiring to fill key vacancies in certain areas over the planning period. Through filling of existing vacancies, headcount is expected to increase by 80 employees year over year in 2018, before beginning to decline thereafter.

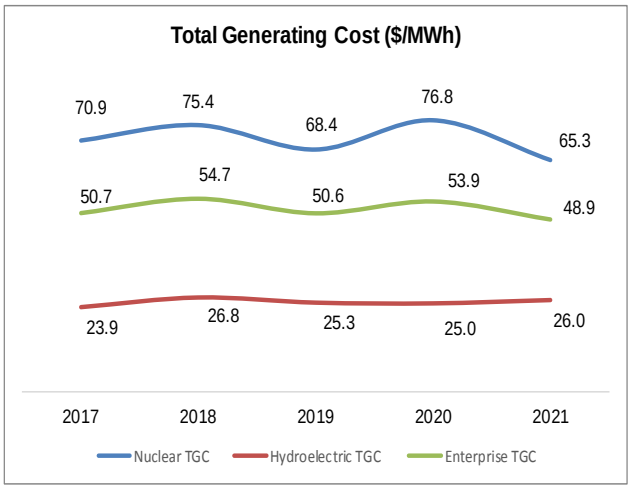
By the end of 2021, headcount is expected to be ~255 lower than at the end of 2018, reflecting efficiency improvement and organizational redesign initiatives and the impact on work programs from the approaching Pickering end of life. These reductions are expected to be realized by leveraging attrition and through selective use of temporary resources in line with collective agreement provisions. The decline in future staffing levels also reflects the expiry of the current Thunder Bay biomass energy supply agreement in 2020.

Staffing levels discussed above include PWU Term Employees. The plan assumes continued utilization of this category of non-regular employees negotiated in the 2015 round of collective bargaining with a view to adding fewer regular staff in circumstances where they are likely to be laid off as a result of the end of Pickering commercial operations. Term Employees attract a lower termination cost than regular PWU employees, do not receive pension or benefits from OPG and represent a key strategy to mitigate downsizing costs upon retirement of Pickering. The plan reflects an addition of ~300 PWU Term Employees over the period, primarily in the Nuclear organization, bringing the total number of PWU Term Employees to ~440 by 2021. Continued use of Term Employees requires renegotiation as part of the 2018 round of collective bargaining.

Collective bargaining results will also continue to impact future OEB rate application outcomes, as OEB cost disallowances have been historically based, in part, on OPG's compensation benchmarking including wages, pension and benefits. While OPG has made progress in containing unionized employee wage costs and implementing pension reform in the last round of bargaining, it must seek to continue to make further gains in this area in order to improve its cost structure.

### Total Generating Cost

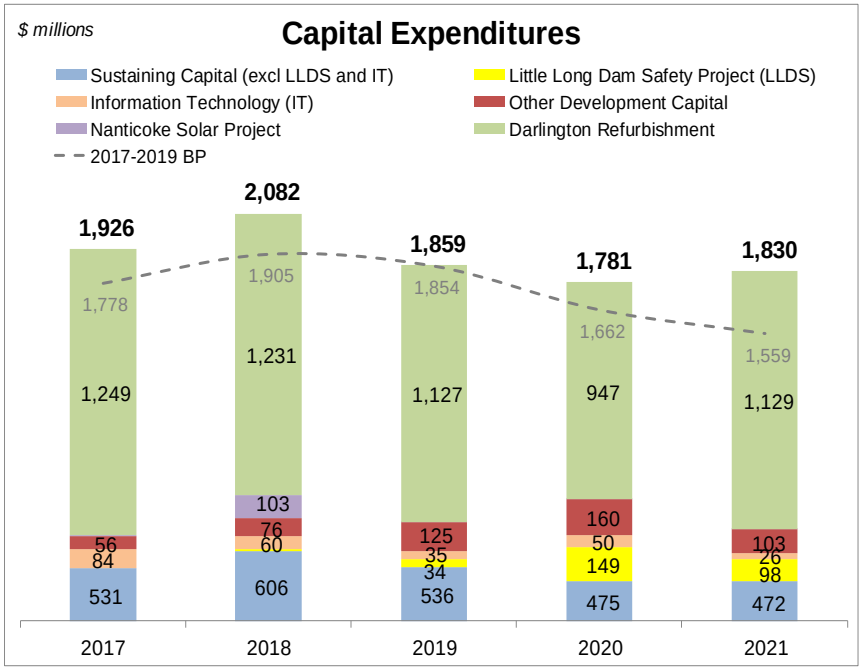
Total Generating Cost (TGC) per MWh is OPG's enterprise-wide measure of operational cost effectiveness. The measure includes OM&A expenses from ongoing operations, fuel expense (including gross revenue charge and other water rental costs) and sustaining capital expenditures, and is calculated on SBG-adjusted production volumes. In addition to continuing to exclude development capital expenditures, the measure also excludes expenditures on two planned large hydroelectric projects, the $200 million Sir Adam Beck I GS Water Conveyance System project and the $300 million Little Long Dam Safety project, starting with this planning cycle.




Targets for Enterprise TGC per MWh over the period range from a low of $48.9 (in 2021) to a high of $54.7 (in 2018), compared to $50.7 in 2017. The fluctuations in the measure over the period reflect the nuclear outage profile, including the Pickering VBO and Darlington refurbishment-related outage impacts, initiatives to reduce OM&A costs, variability in sustaining capital expenditure levels and, in 2017, high SBG-adjusted hydroelectric production due to extremely high water levels. If Darlington units were not undergoing refurbishment and would continue to operate consistent with targeted performance for the station's un-refurbished units and if the Pickering units would continue to operate in lieu of the VBO, the plan would yield Enterprise TGC per MWh targets of ~$5 lower, on average. The 2017 metric on this basis would have been similarly lower.

## Project Excellence

Asset base growth through investment in existing assets, organic development and acquisition is a key element of OPG's strategy to achieve sustainable increases in profitability and ROE levels and to maintain appropriate scale in the longer term.




In addition to refurbishing the Darlington station, OPG's planned capital program will continue to make investments in sustaining and improving the performance of existing assets and will continue to execute the organic growth element of the corporate strategy, including through relatively modest expansion of hydroelectric generating capacity, completion of the Nanticoke solar facility and investments in nuclear and other low-carbon technology innovation complementary to OPG's core competencies. The planned capital program is aligned with the 2017 LTEP.

Total capital expenditures planned for the Darlington refurbishment, sustaining investments in existing assets and organic development projects are $7.5 billion over the 2018-2021 period, ranging from $1.8 billion to $2.1 billion per year. Over the period, this represents an increase of ~$570 million compared to the previous plan. The major drivers of the increase are timing of Darlington refurbishment expenditures (~$105 million), incremental investment in Darlington sustaining capital (~$120 million), accelerated digital transformation strategy (~$40 million), and incremental funding for potential organic growth opportunities (~$200 million). As discussed under the Financial Strength section, non-organic growth investments are not assumed in the plan and will need to be aligned with market opportunities and Shareholder's expectations.

**Darlington Refurbishment**

Darlington refurbishment expenditures total $4.4 billion over the period, an increase of ~$105 million from the previous plan due to timing of expenditures. Consistent with previous business plans and OEB approvals, the plan continues to reflect the high confidence budget and schedule for the Darlington refurbishment, with total cost flow through Unit 2 return to service consistent with Board-approved levels. This includes the D2O Project, which is expected to be completed in the first half of 2019 within the funds already released to the Darlington refurbishment program.

Planned Darlington refurbishment in-service amounts are consistent with amounts approved by the OEB in setting the 2017-2021 regulated rates. In particular, the OEB has allowed inclusion of a total of $5.5 billion in Darlington refurbishment in-service additions through 2021, including pre-requisite projects other than the D2O Project. The plan reflects Unit 2 returning to service in February 2020, with Unit 3 refurbishment commencing immediately thereafter and the third unit refurbishment beginning in 2021. Pre-execution expenditures incurred for the Unit 3 refurbishment, including acquisition of long lead-time materials and components, are $93 million as of 2017 year-end, with a further ~$540 million reflected in the plan over 2018 to February 2020.

**Sustaining Capital**

Total sustaining capital expenditures for nuclear operations are $1.3 billion over the period, declining from ~$385 million in 2018 to ~$245 million in 2021. This represents a total increase of ~$120 million from the previous plan, primarily on account of the Darlington capital program in 2018 and 2019. The program is focused on ensuring Darlington is well positioned to transition to steady-state operations and achieve and maintain industry-leading performance as soon as possible following refurbishment. The increase in expenditures reflects continued optimization of the capital program recognizing historical under-investment relative to peers, with significant plant investments targeted to be completed before multiple Darlington units are under refurbishment later in the plan. These investments include life cycle management projects, upgrades and additions of facilities, and work in support regulatory commitments. The Darlington capital program is expected to decline toward the end of the planning period and during the remainder of the refurbishment period. Consistent with the previous plan, the Pickering capital program declines over the period in line with the planned end of life in 2024.

OPG remains focused on delivering all projects safely, on time, on budget and with high quality and is committed to executing its capital plan. In 2017, OPG delivered on its capital program commitments with aggregate spending on sustaining capital projects meeting internal targets. To improve consistency of project outcomes across the organization, OPG has implemented common enterprise-wide project governance and a scalable project delivery model, as well as project management system and tools, leveraging industry standards. OPG is also focused on strengthening internal project management capability, with project management proficiency development programs launched in 2017 for existing and new project managers. In 2018, OPG will transition to an enterprise wide Project Management Centre of Excellence that will provide portfolio and project management standards and services for all projects across OPG.

In setting OPG's nuclear regulated rates for 2017-2021, the OEB disallowed certain capital project costs based on an assessment of OPG's performance on the projects, reduced OPG's forecast of 2017-2021 non-Darlington refurbishment capital in-service additions based on an assessment of OPG's ability to deliver on the capital plan, and applied an accumulating annual efficiency stretch factor of 0.6% to reduce

revenues earned by OPG from an allowed level of forecast in-service additions. Continuing to execute the capital program as planned and delivering on efforts to improve project performance will support improved outcomes of OEB's future assessments of OPG's capital costs.

Excluding the Sir Adam Beck I GS Water Conveyance System project, regulated hydroelectric sustaining capital expenditures total ~$510 million over the 2018-2021 period, an average ~$125 million per year, consistent with the previous plan. This includes a number of projects to maintain and enhance availability when needed and reliability as well as increase capacity of OPG's renewable fleet, including:

- Unit overhauls and upgrades across the fleet, including Sir Adam Beck 1, Sir Adam Beck Pump, R.H. Saunders, Otto Holden, Barrett Chute and Silver Falls generating stations.
- Flow control equipment replacements in Northwest Operations including automatic sluicegate system replacements at Whitedog Falls GS and Caribou Falls GS scheduled for completion in 2019 and 2020 respectively; and
- Electrical equipment, headgate and sluicegate replacements in Eastern Operations including generator breaker replacements at Des Joachims GS, to be completed in 2020 and 2021;

Planning work on the $200 million Water Conveyance System project to rehabilitate the Sir Adam Beck I GS power canal and associated structures has commenced. The project will repair concrete deterioration and restore the original flow capacity of the power canal, ensuring reliable operations for the next 50 years. The project is expected to come into service over two years following the start of execution.

Contracted hydroelectric sustaining expenditures include the $300 million Little Long Dam Safety project (formerly the Lower Mattagami Dam Safety project), planned to be completed by 2022. The project will address dam safety requirements on the Lower Mattagami River in line with OPG's commitment to dam safety excellence, earning a return under the Lower Mattagami hydroelectric energy supply agreement once in service. Total project expenditures are consistent with the previous plan, but have been deferred to start later in the planning period.

Sustaining expenditures include ~$170 million for information technology projects, including an increase of ~$40 million over the previous plan for investments in OPG's accelerated digital transformation strategy, largely over 2018 and 2019. The digital transformation strategy will serve as an enabler to productivity improvements and business optimization opportunities, by modernizing OPG's information technology infrastructure and by providing the technology foundation and tools aimed at maximizing workforce and field productivity and efficiency across the organization. Projects are focused on four key strategic areas: Digital Modernization; Generation Support; OPG25 Support; and Infrastructure Improvement. More than half of the projects are to be invested directly in the generation business units. OPG will also continue to make investments in maintaining a reliable, cyber-safe information technology environment and reducing cyber-related operational risks.

**Business Development Capital**

Organic development expenditures over the planning period total ~$570 million. This includes previously planned projects as well as incremental funding of ~$200 million for organic business development opportunities. Previously planned projects include completion of the Ranney Falls GS redevelopment, construction of the Nanticoke solar facility, frequency conversion of Sir Adam Beck GS Units 1 and 2 to 60 Hz to increase capacity, and potential redevelopment of the Calabogie GS. The Ranney Falls GS project is tracking on schedule and on budget, construction of the Nanticoke facility is scheduled to begin in the first quarter of 2018, the Sir Adam Beck frequency conversion is planned to begin execution in 2019, and the Calabogie GS redevelopment is being assessed as part of the definition phase. The Ranney Falls GS and the Nanticoke solar facility are scheduled to come into service during 2019.

Incremental funding for potential organic business development investments included in the plan contemplates such additional opportunities as expansion of nuclear isotopes sales and nuclear services, future regulation procurement projects and an investment in a disruptive innovation venture fund. OPG will continue to strategically assess investment opportunities for decarbonising, disruptive energy sector technologies beyond the Company's core generation portfolio, with the goal of building a competitive advantage in this area.

OPG has been successful with the organic growth element of its strategy, including through recent completion of the 28 MW Peter Sutherland Sr. GS, and will continue to explore broader business expansion opportunities as described above. Nevertheless, organic growth opportunities in Ontario's electricity sector remain limited including due to uncertain future electricity demand levels, and OPG's current asset portfolio continues to be heavily weighted on Ontario-centric regulated nuclear and hydroelectric generation. The non-organic element of OPG's corporate strategy, executed in a paced manner with due consideration of core operational and financial impacts, is therefore essential to ensuring that OPG is ultimately able to deliver appropriate Shareholder value and improve its risk profile.

**Provision Expenditures**

Planned expenditures against a previously established provision for nuclear station decommissioning and waste management average ~$350 million per year over the 2018-2021 period. The expenditures include costs for ongoing used fuel and low & intermediate level waste interim storage operations and projects, the planning phase of the Pickering Safstor project, Nuclear Waste Management Organization's siting process activities for the Adaptive Phased Management used fuel disposal program, and continuing activities in support of obtaining a preparation and construction licence for the L&ILW DGR. The plan supports OPG's ongoing commitment to continued engagement with the Saugeen Ojibway Nation toward securing support for the L&ILW DGR, including developing a response to the federal Minister of Environment and Climate Change request for OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's physical and cultural heritage, taking into account the results of the Saugeen Ojibway Nation Community Process. In recognition of inherent uncertainty in the ultimate impact of the Environmental Assessment decision on the timing of project construction, planned expenditures on the L&ILW DGR project over the 2018-2021 period are ~$400 million lower than in the previous plan. Nuclear provision expenditures are funded from the nuclear segregated funds for decommissioning and long-term management of fuel and waste and from operating cash flow for interim storage operations.

The plan also includes provision expenditures of ~$75 million and ~$85 million over the period to 2021 for decommissioning of the former Nanticoke GS by 2020 and the former Lambton GS by 2021, respectively. Projected decommissioning expenditures for these sites reflect more advanced planning and contract scope details.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust and building the Company's brand. OPG works to maintain public trust through community engagement, transparency, corporate citizenship initiatives and Indigenous relations. OPG focuses on building and maintaining its social licence through safe, reliable, environmentally-responsible operations that continue to mitigate Ontario's electricity prices, support climate change initiatives and foster diversity and inclusion in the workplace.

**Supporting Decarbonisation and Climate Change Goals**

OPG is proud of its transition to a low-carbon electricity generation portfolio and is helping the Province meet its climate change and greenhouse gas reduction commitments. With a generating fleet that is 99% emission-free, OPG avoids over 30 million tonnes of greenhouse gas emissions annually in comparison to a fleet of gas generators. To ensure a supply of clean power for generations to come, OPG's operational and organic growth strategies are focused on innovation, technology, and energy and storage development. This includes maintaining the nuclear portion of OPG's generation portfolio, participating in the development of new nuclear technologies, evaluating and implementing plans to increase hydroelectric generation, and investing in other low-carbon technologies. Through investment in these areas, OPG seeks to support Ontario's climate change goals while building momentum for new business opportunities. OPG's business plan supports Ontario's climate change goals through a transportation electrification strategy, participation in Ontario's cap and trade program, organic expansion of the renewable generating fleet and the supply of safe, reliable and clean power to homes, businesses and industry throughout the province.

The goal of OPG's transportation electrification strategy is to position the Company as a leader in the electrification of Ontario's transportation sector. As part of the strategy, OPG is implementing fleet-wide electric vehicle adoption goals and charging station infrastructure across the Company's work locations, and is assessing vehicle-grid integration and hydrogen applications for the transportation sector. This strategy is intended to leverage OPG's clean, reliable and cost-effective electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

OPG has been a participant in Ontario's cap and trade program since it came into effect on January 1, 2017. This market-based program sets an annual cap for greenhouse gas emissions, with targets becoming more stringent over time. Compliance with these requirements does not have a significant financial cost impact on OPG's business plan given OPG's virtually emission-free generating fleet and the contractual arrangements in place for the greenhouse gas emitting assets in OPG's fleet.

Looking ahead, climate change and the extreme weather associated with it could pose strategic risks for OPG. Longer term changes in precipitation patterns and amounts, water temperatures, and ambient air temperatures can impact the availability and quality of water resources for OPG's operations. These changes could potentially affect electricity production at hydroelectric stations, and cooling water efficiency at nuclear and thermal stations. To date, OPG has not experienced significant impacts attributable to climate change or extreme weather, but the Company is assessing the short and long-term risks and identifying climate change adaptation requirements. OPG continues to participate in climate change adaptation initiatives with municipal and regional governments, the Ontario Ministry of the Environment and Climate Change, the Ontario Ministry of Energy, and Natural Resources Canada. OPG is also monitoring developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements.

New guidance is expected shortly for North American listed public companies that will see a stronger emphasis on climate-related disclosures and reporting requirements as part of the financial reporting framework. Given OPG's commitment to climate change mitigation, the Company will position itself to move toward a leadership position in this area and will increase disclosures in regulatory filings during 2018.

**Pursuing Clean Energy Business Development Opportunities**

Expanding clean generation from the Company's renewable generation fleet is a key focus of OPG's organic business development plans. As detailed in the Operational Excellence and Project Excellence sections, OPG expects to add approximately 170 MW of renewable generation capacity to its fleet over the business plan period, including through construction of a 44 MW solar facility at the former Nanticoke GS site in partnership with the Six Nations of the Grand River and investments in developing, re-developing and upgrading of hydroelectric facilities. OPG will continue to optimize electricity production and seek opportunities to further expand capacity from its province-wide hydroelectric fleet by balancing the economic, environmental, social, and legal requirements associated with the affected watersheds.

OPG sees significant socio-economic and commercial potential in the role that nuclear energy can continue to play in a decarbonizing economy. In addition to making significant investments in OPG's existing nuclear fleet to continue to provide Ontario with cost-effective, carbon-free baseload generation, through refurbishment of Darlington and extension of Pickering operations to 2024, OPG plans to strategically participate in the development of potential innovative and advanced nuclear reactor technologies. As Canada's largest nuclear operator with extensive experience, a strong safety record and a commitment to climate change mitigation, OPG is well positioned to be a pan-Canadian driving force in this area. With respect to OPG's existing nuclear operations, it is expected that the refurbished Darlington station will reduce greenhouse gas emissions by an estimated 297 million tonnes over its life, which is the equivalent of removing two million fossil-fuelled cars per year from Ontario's roads.

In addition to being a mainstay of Ontario's baseload electricity supply, OPG's nuclear operations continue to be a source of important isotopes that serve significant needs in society. From the life-saving Cobalt-60 isotope, which sterilizes medical devices and food, to tritium, which can act as a self-powered light source, these innovative nuclear products help millions of people around the world. Isotope production is an example of a good business opportunity for OPG that validates the Company's social licence and Power with Purpose vision.

**Partnering with Indigenous Communities**

OPG is committed to continuing to build mutually beneficial working relations with Indigenous communities proximate to the Company's current and future operations. The Company believes and takes pride in establishing and maintaining these relationships through dialogue founded in respect and aimed at preserving openness, transparency and trust. These strong partnerships are vital to maintaining OPG's social licence in the communities and are a source of critical competitive advantage while developing clean, renewable power in the province.

Throughout the planning period, OPG will continue to engage proactively with Indigenous communities, people, businesses and organizations through a number of diverse initiatives. This includes pursuing additional generation-related development partnerships, collaborating on capacity building initiatives and projects, and continuing to conduct community outreach efforts. As part of capacity building, OPG will continue to advance its Indigenous Business Engagement initiative that will increase Indigenous access to procurement opportunities, as well as to expand Indigenous recruitment initiatives aimed at increasing employment opportunities, including in the nuclear generation industry. As a member of the Canadian Council of Aboriginal Businesses, OPG is also working towards a new assessment submission in 2018 under the Council's Progressive Aboriginal Relations certification program, with the goal of achieving a Gold certification.

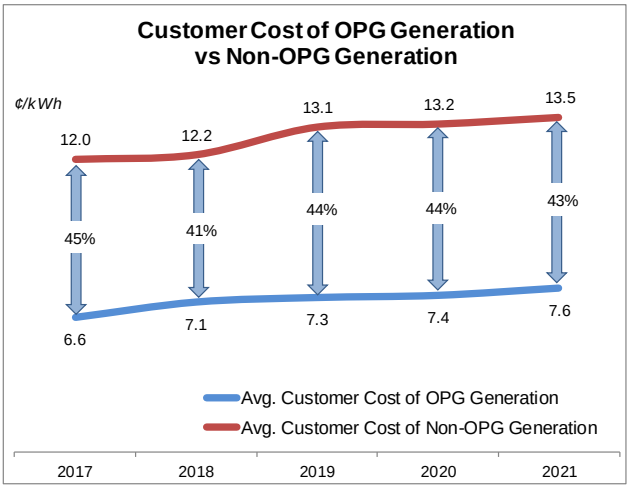
OPG continues its engagement with Indigenous communities regarding the Company's nuclear operations, including collaboration with the Saugeen Ojibway Nation in respect of the proposed L&ILW DGR. OPG has previously committed that the project would not proceed without Saugeen Ojibway Nation's support. OPG is also proactively engaging with Indigenous communities proximate to the Pickering station regarding the station's relicensing and collaborated with the CNSC to ensure access to participant funding in the hearing process.

**Expanding the OPG Brand and Creating a Diverse, Progressive Workforce**

In support of its strategic direction, OPG continues to expand its branding efforts to reinforce the Company's social licence, increase stakeholder awareness and build a stronger presence amongst the public. Power with Purpose remains the platform for the Company's key outreach and branding initiatives. OPG will continue to use Power with Purpose to emphasize the Company's role as a leader in clean energy generation and innovation, as a cost-effective moderator of electricity prices, and as a driver of economic and community well-being. Additionally, a new "Be the Generation" recruitment campaign to appeal to both prospective and current employees is being developed. Be the Generation aims to present the opportunities to make a difference when working for OPG as a forward-looking company that takes pride in caring about people, the environment, the economy and the future. Likewise, OPG's "Made in Ontario" campaign will continue to capture OPG's efforts to secure a clean energy future for the province.

OPG is focused on building a workforce that is representative of the communities and customers it serves and is committed to provide a diverse and equitable workplace where all employees can realize their full potential with equal access to opportunities. In support of this, OPG has developed a long-term Diversity and Inclusion strategy into 2020, reflected its commitment in the performance contracts of all Company's executives, and strives to hire diverse candidates by reaching out to designated groups and including diversity in succession plans. Leveraging the unique perspectives, talents and experiences of a diverse workforce will enable OPG to grow and compete well into the future.

## Moderating Electricity Prices and Contributing to the Economy




The plan reflects the OEB's decision on OPG's 2017-2021 rate application, which, based on OPG's proposed payment amounts order, will result in a consistent annual increase of 0.4% or $0.65 on the typical residential customer's monthly bill during the 2017 to 2021 period. Taking into the account this impact, the average cost to customers of electricity generated by OPG will continue to track approximately 40% below the average of non-OPG cost of electricity in Ontario over the period to 2021.

The forecast trajectory of OPG's average cost reflects nuclear regulated rates under rate smoothing proposed in OPG's payment amounts order submission, as well as a forecast of regulated hydroelectric rates under the OEB-approved incentive regulation formula. The increase in the non-OPG cost of electricity in 2019 reflects the terms of the refurbishment agreement between Bruce Power and IESO, whereby Bruce Power begins to receive a higher price commencing one year before the first unit is scheduled to commence refurbishment in 2020.

The average non-OPG cost of electricity trajectory over the business plan term is higher than OPG's forecast in the previous plan. This is primarily due to an updated OPG forecast of wind and solar electricity system costs based on updated non-OPG renewable generation cost information published by the IESO, and a reduction in the annual Ontario grid demand forecast averaging 2.5 TWh. Lower grid demand decreases the need for gas generation that is used to spread the fixed portion of non-OPG generator costs, thereby increasing the average non-OPG cost.

OPG will continue to make a significant contribution to the Ontario economy and job creation, including through the refurbishment and continued operation of the Darlington station and extending the operating life of the Pickering station to 2024. In addition to continuing to powering one in every five homes in Ontario, the Darlington station's refurbishment and subsequent operation are estimated to boost Ontario's Gross Domestic Product by $90 billion and create and sustain over 14,000 jobs annually over the station's life.

## Engaging Electricity Consumers

Customer engagement is a priority for OPG, both because of its social license strategic imperative and because of its largely regulated operations. OPG routinely engages customers and opinion leaders through provincial and host community surveys, community liaison groups, focus groups, and ongoing contact with key industry associations. Engagement topics cover areas of critical importance to OPG's business, including safety, reliability and environmental protection. The OEB increasingly expects regulated utilities' business plans to be shaped by customer engagement. The OEB has confirmed that, although OPG does not have a direct transactional relationship with electricity consumers, it expects OPG's business plans to be informed by customer engagement. OPG has committed to more formally incorporate customer engagement into its business planning process over time and will build on its existing customer engagement activities as it prepares subsequent business plans.

## APPENDIX 1: KEY PLANNING ASSUMPTIONS

### Operational and Project Assumptions

- Refurbishment of Darlington Unit 2 is completed by February 2020, with Unit 3 refurbishment starting immediately after Unit 2 is returned to service and Unit 1 refurbishment starting in 2021. D2O Project is in service in the first half of 2019
- Pickering station operates until 2024. The plan includes additional costs and outage days to enable Pickering operations beyond 2020, in line with the business case approved by the Board
- A station-wide Vacuum Building Outage takes place at Pickering in 2020
- The plan reflects currently approved accounting station service lives for Pickering Units 1 & 4 to 2022, Pickering Units 5-8 to 2024, Darlington to 2052, Bruce Units 1-4 to 2052 and Bruce Units 5-8 to 2061
- Employee termination costs related to the Pickering closure are not included in the plan. Accounting criteria requiring recognition of a liability for these costs are assumed to be met in 2022 at the earliest
- Site preparation and construction licence is received for the proposed L&ILW DGR
- Incremental funding is allocated in the plan for potential initial planning and preparation activities related to the study of new nuclear facilities. The new nuclear Darlington site preparation licence is maintained
- Sir Adam Beck I GS Units 1 & 2 are converted to 60 Hz frequency, with the first unit in service in 2021
- Sir Adam Beck I GS power canal rehabilitation takes place over 2021 and 2022, subject to optimization of major project work sequencing in Renewable Generation
- Ranney Falls GS project is in service in 2019 and Little Long Dam Safety project is completed by 2022
- Nanticoke solar facility is in service in the first quarter of 2019. Former Nanticoke GS and Lambton GS are decommissioned, with demolition and site brownfield completed by 2020 and 2021, respectively
- Thunder Bay GS operates until the end of current biomass energy supply agreement in January 2020
- First Bruce unit refurbishment starts in 2020, as per the Bruce Power refurbishment agreement
- Assumed Ontario grid demand growth rate is approximately 0% on average over the planning period

### Financial and Rate Regulation Assumptions

- OEB approves nuclear base rates and rate smoothing deferrals to 2021 as proposed in OPG's January 2018 draft payment amounts order. Hydroelectric base rates increase by 1% in 2019 and by 1.5% in each of 2020 and 2021 under the OEB-approved incentive regulation formula
- OPG's next deferral and variance account application is filed in 2018, with OEB approving clearance of the pension and OPEB cash-to-accrual deferral account as part of the application
- Lakeview site sale takes place in the first quarter of 2018, with a corresponding dividend paid in 2018, in addition to the dividend related to the sale of the 700 University Ave. property. No other dividends are assumed pending review and formalization of a capital allocation policy
- Acquisitions are not included in the plan as opportunities are evaluated as they arise
- Nuclear Fund investments earn 5.15%/yr
- Pension fund investments earn 6%/yr. Accounting discount rates for valuing the benefit obligation for pension and other post-retirement benefits are 3.8% and 3.9%, respectively
- The plan reflects the January 1, 2017 actuarial funding valuation of OPG's registered pension plan as filed with the regulator and assumes a subsequent valuation as of January 1, 2020
- Pending the outcome of 2018 round of bargaining, inflationary impacts on salary costs are assumed post current collective agreements. Ability to utilize PWU Term Employees is assumed to continue
- Both OEFC credit facilities and public debt platform are used for long-term corporate debt purposes. Effective interest rate for new OPG debt over the planning period is 5.0%, on average
- The plan reflects OPG's role as the Financial Services Manager of the Fair Hydro Plan, including consolidation of the Fair Hydro Trust. Effective interest rate for Fair Hydro Trust senior debt over the planning period is 4.25%, on average
- OPG continues to prepare its consolidated financial statements and report its financial results in accordance with US GAAP

## APPENDIX 2: KEY RISKS

The key risks associated with the 2018-2021 Business Plan are outlined below.

### Operational and Project Risks

- Failure to maintain the Darlington refurbishment cost and schedule commitments per the approved project budget and schedule
- Inability to meet the objectives of the first unit refurbishment, resulting in sub-optimal post-refurbishment performance
- Risk of the Province not concurring with the refurbishment of subsequent Darlington units
- Inability to achieve production targets, including risks associated with unit capability factors, planned nuclear outage performance, nuclear station lifecycle management, and human performance
- Risk of increased operating costs as a result of greater-than-planned deterioration of station components and systems, discovery of unexpected conditions, and/or equipment failures
- Risk of technical challenges in confirming ability to operate Pickering beyond 2020, and/or failure to obtain regulatory assurance from the CNSC in support of the station's continued operations, including inability to renew the operating licence without conditions
- Inability to progress realignment of the Company's cost structure and operating model in line with the OPG25 plan
- Inability to retain and attract leadership talent and qualified management employees during the Darlington refurbishment and continued Pickering operations, and/or inability of management and staff to adapt to OPG's evolving corporate culture and higher level of commercial discipline
- Failure to appropriately staff operational and support groups in critical skill areas given ongoing demographic challenges and strategies aimed at mitigating Pickering closure downsizing impacts

### Financial and Rate Regulation Risks

- Risk of unfavourable outcomes of the 2018 round of collective bargaining, which could impact operating costs, Pickering closure employee termination costs and future OEB rate application outcomes
- Risk of requirement to recognize employee termination costs associated with the Pickering end of commercial operations prior to 2022, which would require assurance over the costs' future recovery in order to avoid a significant charge against net income
- Lack of material growth investments and eventual loss of scale leading to increased risk of inability to withstand unplanned events, diminished ability to support de-carbonisation goals and erosion of Shareholder value
- Risk of federal approval process for L&ILW DGR resulting in significant changes to OPG's nuclear waste management strategies and associated financial obligations, impacting net income and future required contributions to the nuclear segregated funds
- Risk of lower than planned returns on nuclear segregated and pension fund assets as a result of market factors, including equity prices, interest rates, inflation and commodity prices, which would lower net income and potentially increase future funding requirements
- Risk of lower discount rates and other changes in assumptions for future pension and OPEB valuations
- Risk of adoption of IFRS for financial reporting purposes due to inability to extend the Ontario Securities Commission exemption that allows OPG to prepare consolidated financial statements under US GAAP. Adoption of IFRS would be expected to cause significant net income volatility compared to US GAAP

## APPENDIX 3: Financial and Headcount Plan Information

| Key Financial Metrics<br>*(in millions of dollars unless otherwise noted)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Financial Performance Metrics*** | | | | | |
| Net Income Attributable to Shareholder | 860 | 1,043 | 1,066 | 919 | 1,373 |
| Operating Net Income Attributable to Shareholder | 576 | 795 | 968 | 764 | 1,160 |
| Earnings Before Tax | 1,090 | 1,140 | 1,239 | 1,147 | 1,649 |
| Total Return on Equity* | 7.6% | 8.1% | 7.2% | 5.4% | 7.1% |
| Operating Return on Equity* | 5.3% | 6.8% | 7.7% | 5.7% | 8.1% |
| Debt Ratio, excl. Fair Hydro Trust**** | 34% | 36% | 33% | 30% | 26% |
| FFO / Total Debt Ratio, including Fair Hydro Trust Impact *(Minimum threshold of 9%)* | 10% | 11% | 12% | 13% | 13% |
| FFO / Total Debt Ratio, excluding Fair Hydro Trust Impact | 10% | 13% | 15% | 17% | 19% |
| Debt / EBITDA Ratio, including Fair Hydro Trust Impact (times) *(Maximum threshold of 5.5)* | 6.8 | 6.5 | 6.2 | 6.2 | 6.0 |
| Debt / EBITDA Ratio, excluding Fair Hydro Trust Impact (times) | 6.4 | 5.8 | 5.1 | 4.8 | 4.3 |
| Total Debt at Year-End | 6,579 | 8,757 | 9,768 | 10,978 | 11,777 |
| Net Cash from Operations | 944 | 1,460 | 2,384 | 2,067 | 2,642 |
| Total Return to Shareholder, excluding Fair Hydro Trust Earnings*** | 1,393 | 1,391 | 1,422 | 1,259 | 1,667 |
| | | | | | |
| ***Cost Performance Metrics*** | | | | | |
| Nuclear Total Generating Cost** *($/MWh)* | 70.9 | 75.4 | 68.4 | 76.8 | 65.3 |
| Hydroelectric Total Generating Cost** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |
| Enterprise Total Generating Cost** *($/MWh)* | 50.7 | 54.7 | 50.6 | 53.9 | 48.9 |
| OM&A Expenses from Ongoing Operations | 2,819 | 2,850 | 2,732 | 2,807 | 2,570 |
| Darlington Refurbishment Capital Expenditures | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Darlington Refurbishment In-Service Additions | 305 | 24 | 335 | 4,698 | - |
| Capital Expenditures excluding Darlington Refurbishment | 677 | 851 | 731 | 834 | 700 |
| In-Service Additions excluding Darlington Refurbishment | 968 | 719 | 876 | 527 | 804 |
| Nuclear Waste and Thermal Decom. Provision Expenditures | 313 | 373 | 411 | 435 | 377 |

* Calculated using the methodology per OPG's external financial filings

** Total Generating Cost is calculated as: (OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures)/OPG generation adjusted for surplus baseload generation losses. Sustaining capital expenditures exclude the Little Long Dam Safety project and the Sir Adam Beck 1 GS Water Conveyance System Project. Absent Darlington refurbishment and Pickering VBO, Enterprise TGC would be ~$5/MWh lower on average each year

*** Calculated as: Net Income Attributable to Shareholder + Income Taxes + Gross Revenue Charge + Property Tax PILs

****Excludes Class A Shares and Fair Hydro Trust Senior Debt

| Operating Statement - Years Ended December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| Electricity Generation Revenues | 4,823 | 4,975 | 5,583 | 5,788 | 5,404 |
| Fuel and Gross Revenue Charge | 689 | 674 | 686 | 654 | 626 |
| **Generation Sales Gross Margin** | **4,134** | **4,301** | **4,898** | **5,134** | **4,778** |
| Net Trading Margin | 15 | 18 | 18 | 18 | 18 |
| Non-Electricity Generation Gross Margin | 302 | 258 | 249 | 253 | 235 |
| **Total Gross Margin** | 4,450 | 4,577 | 5,165 | 5,406 | 5,032 |
| OM&A Expenses (excl. Cost of Goods Sold) | 2,806 | 2,827 | 2,773 | 2,914 | 2,596 |
| Depreciation and Amortization | 679 | 743 | 1,139 | 1,318 | 950 |
| Accretion on Nuclear Waste and Other Liabilities | 960 | 991 | 1,023 | 1,055 | 1,091 |
| Earnings on Nuclear Funds | (801) | (855) | (892) | (928) | (965) |
| Earnings from Fair Hydro Trust | (1) | (64) | (131) | (206) | (285) |
| Property Taxes | 40 | 37 | 38 | 38 | 40 |
| Restructuring | - | - | 10 | - | - |
| **Total Expenses** | 3,683 | 3,679 | 3,961 | 4,191 | 3,426 |
| **Income before Interest and Other Income** | **768** | **897** | **1,204** | **1,215** | **1,605** |
| Net Interest Expense | 95 | 78 | 5 | 102 | (9) |
| Other (Income)/Expense* | (417) | (320) | (40) | (35) | (35) |
| **Income before Tax** | **1,090** | **1,140** | **1,239** | **1,147** | **1,649** |
| Income Tax | 209 | 79 | 154 | 209 | 255 |
| **Net Income** | **881** | **1,061** | **1,085** | **938** | **1,394** |
| **Net Income Attributable to Shareholder** | **860** | **1,043** | **1,066** | **919** | **1,373** |
| Net Income Attributable to Non-Controlling Interests | 21 | 18 | 19 | 20 | 21 |

* Includes $28M and $10M in 2017, $26M and $12M in 2018, $28M and $13M in 2019, $27M and $11M in 2020, $27M and $10M in 2021, representing OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre and the Brighton Beach GS, respectively. In 2017, a pre-tax gain of $378M on the sale of 700 University Ave. property is included. In 2018, a pre-tax gain of $267M on the sale of the Lakeview site is included.

| Balance Sheet - As at December 31<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| ***Assets*** | | | | | |
| **Current assets** | | | | | |
| Cash and cash equivalents | 234 | 273 | 354 | 249 | 301 |
| Short-term investments | 188 | 167 | 148 | 130 | 112 |
| Accounts receivable | 515 | 579 | 607 | 546 | 567 |
| Fuel inventory | 309 | 297 | 231 | 218 | 183 |
| Materials and supplies | 103 | 103 | 103 | 103 | 103 |
| Other current assets | 192 | 192 | 192 | 192 | 192 |
| | 1,541 | 1,612 | 1,635 | 1,438 | 1,458 |
| **Property, plant and equipment and intangible assets** | | | | | |
| Fixed and intangible assets (net) | 21,455 | 22,774 | 23,891 | 24,781 | 25,741 |
| **Other assets** | | | | | |
| Financing Receivables | 1,179 | 3,505 | 6,062 | 8,874 | 11,615 |
| Nuclear fixed asset removal and nuclear waste management funds | 16,724 | 17,473 | 18,233 | 19,009 | 19,811 |
| Long-term materials and supplies | 355 | 301 | 289 | 276 | 262 |
| Regulatory assets (net)* | 6,637 | 6,715 | 6,299 | 6,200 | 6,309 |
| Investments subject to significant influence | 309 | 301 | 291 | 278 | 263 |
| Other long-term assets | 28 | 28 | 28 | 28 | 28 |
| | 25,231 | 28,323 | 31,202 | 34,666 | 38,287 |
| ***Total Assets*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |
| ***Liabilities*** | | | | | |
| **Current liabilities** | | | | | |
| Short-term notes payable | 260 | 460 | 410 | 485 | 100 |
| Accounts payable and accrued charges | 1,228 | 1,140 | 1,092 | 1,072 | 1,238 |
| Deferred revenue due within one year | 12 | - | - | - | - |
| Current income taxes payable | 80 | 37 | 83 | 39 | 197 |
| Long-term debt due within one year | 398 | 368 | 663 | 413 | 153 |
| | 1,978 | 2,006 | 2,248 | 2,008 | 1,688 |
| **Long-term debt** | 5,921 | 7,929 | 8,695 | 10,080 | 11,524 |
| **Other liabilities** | | | | | |
| Fixed asset removal and nuclear waste management liabilities | 20,421 | 21,167 | 21,921 | 22,677 | 23,521 |
| Pension liabilities (non-current) | 3,423 | 3,353 | 3,275 | 3,195 | 3,098 |
| Other post-employment benefit liabilities (non-current) | 3,092 | 3,183 | 3,275 | 3,371 | 3,461 |
| Long-term accounts payable and accrued charges | 252 | 256 | 238 | 248 | 245 |
| Deferred revenue | 351 | 419 | 410 | 401 | 392 |
| Deferred income taxes | 879 | 904 | 984 | 1,073 | 1,149 |
| | 28,417 | 29,282 | 30,103 | 30,964 | 31,867 |
| ***Equity*** | | | | | |
| Class A shares | 519 | 1,540 | 2,664 | 3,899 | 5,105 |
| Common shares | 5,126 | 5,126 | 5,126 | 5,126 | 5,126 |
| Retained earnings | 6,396 | 6,957 | 8,024 | 8,942 | 10,316 |
| Accumulated other comprehensive loss | (295) | (292) | (291) | (290) | (290) |
| Equity attributable to non-controlling interests | 165 | 161 | 158 | 154 | 151 |
| | 11,911 | 13,493 | 15,681 | 17,832 | 20,407 |
| ***Total Liabilities and Equity*** | **48,228** | **52,709** | **56,727** | **60,884** | **65,486** |

* Includes accrued revenues for new regulated rates for the period from June 1, 2017 to the implementation date of the OEB's decision. The accrued balance is assumed to be collected beginning January 1, 2019 over 3 years.

| OM&A Expenses by Business Unit<br>*(in millions of dollars)* | Actual 2017* | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Nuclear Operations | 1,709 | 1,736 | 1,686 | 1,792 | 1,554 |
| Renewable Generation | 368 | 394 | 395 | 389 | 404 |
| Other Unregulated Operations | 2 | 2 | 2 | 2 | 2 |
| **Total Operations** | **2,079** | **2,132** | **2,083** | **2,184** | **1,960** |
| Chief Administrative Office | 171 | 177 | 170 | 169 | 172 |
| Finance (incl. Chief Information Officer) | 255 | 246 | 232 | 231 | 231 |
| People & Culture | 84 | 79 | 79 | 78 | 78 |
| Corporate Office (inc. Corporate Affairs) | 27 | 25 | 25 | 26 | 26 |
| **Total Support Services** | **537** | **526** | **506** | **504** | **508** |
| **Total Business Unit Expenditures** | **2,616** | **2,658** | **2,590** | **2,688** | **2,468** |
| Insurance | 36 | 40 | 42 | 45 | 46 |
| Centrally Held Pension and OPEB | 95 | 73 | 38 | 5 | (15) |
| Other (incl. Cost of Goods Sold) | 73 | 80 | 63 | 69 | 71 |
| **Total Ongoing Operations** | **2,819** | **2,850** | **2,732** | **2,807** | **2,570** |
| OEB Variance and Deferral Account Offsets | (32) | (34) | 49 | 80 | 14 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| Nuclear New Build** | 0 | 8 | 10 | 12 | 12 |
| **Total OM&A Expenses** | **2,824** | **2,847** | **2,794** | **2,936** | **2,618** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes expenditures budgeted by Support Services

| Production<br>*(TWh)* | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| Darlington | *19.3* | *19.3* | *19.7* | *17.8* | *16.6* |
| Pickering | *21.4* | *19.9* | *21.5* | *18.5* | *21.4* |
| Total Nuclear | 40.7 | 39.2 | 41.2 | 36.3 | 38.0 |
| Regulated Hydroelectric | 30.7 | 30.5 | 30.4 | 31.0 | 29.9 |
| Contracted Generation Portfolio | 2.5 | 2.7 | 2.9 | 3.3 | 3.1 |
| **Total Production (Net of SBG Losses)** | **73.8** | **72.4** | **74.5** | **70.6** | **71.0** |
| Regulated Hydroelectric SBG Losses | 5.2 | 2.7 | 2.7 | 1.5 | 1.3 |
| Contracted Plant SBG Losses | 0.7 | 0.6 | 0.6 | 0.4 | 0.5 |
| **Total SBG Losses** | **5.9** | **3.2** | **3.3** | **1.9** | **1.8** |

| Headcount by Business Unit** | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017* | 2018 | 2019 | 2020 | 2021 |
| Nuclear | 6,176 | 6,171 | 6,149 | 6,119 | 6,067 |
| Renewable Generation | 1,453 | 1,485 | 1,487 | 1,486 | 1,449 |
| Other Unregulated Operations | 6 | 10 | 10 | 10 | 10 |
| **Total Operations** | **7,635** | **7,666** | **7,646** | **7,615** | **7,526** |
| Chief Administrative Office | 572 | 599 | 575 | 558 | 556 |
| Finance (incl. Chief Information Officer) | 690 | 707 | 685 | 670 | 658 |
| People & Culture | 399 | 394 | 384 | 376 | 372 |
| Corporate Office (incl. Corporate Affairs) | 58 | 68 | 68 | 68 | 68 |
| **Total Support Services** | **1,719** | **1,768** | **1,712** | **1,672** | **1,654** |
| **Total Headcount** | **9,354** | **9,434** | **9,358** | **9,287** | **9,180** |

* Actual 2017 amounts have been restated for 2018 organizational changes

** Includes Term employees

| Provision Expenditures<br>*(in millions of dollars)* | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| | 2017 | 2018 | 2019 | 2020 | 2021 |
| **Nuclear Decommissioning and Nuclear Waste Management Expenditures** | | | | | |
| Nuclear Operations* | 276 | 330 | 342 | 347 | 342 |
| Support Services | 14 | 14 | 14 | 14 | 14 |
| **Total Nuclear Provision Expenditures** | **290** | **344** | **355** | **361** | **356** |
| Nanticoke GS Decommissioning | 12 | 13 | 21 | 40 | - |
| Lambton GS Decommissioning | 11 | 15 | 35 | 22 | 14 |
| Other | - | 0 | - | 12 | 7 |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Total Provision Expenditures** | **313** | **373** | **411** | **435** | **377** |

* Includes expenditures for the Darlington Refurbishment Project nuclear waste containers

| Capital Expenditures<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **Sustaining** | | | | | |
| **Nuclear** | 357 | 384 | 353 | 289 | 244 |
| **Regulated Hydroelectric** | | | | | |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Projects | 118 | 144 | 125 | 122 | 117 |
| **Total Regulated Hydroelectric** | 121 | 152 | 133 | 142 | 207 |
| **Contracted Generation Portfolio** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Other Projects | 37 | 45 | 30 | 14 | 8 |
| **Total Contracted Generation Portfolio** | 37 | 51 | 65 | 163 | 106 |
| **Support Services** | | | | | |
| Information Technology Projects | 84 | 60 | 35 | 50 | 26 |
| Other Projects | 16 | 24 | 20 | 29 | 13 |
| **Total Support Services** | 100 | 84 | 56 | 80 | 40 |
| **Total Sustaining Capital** | **615** | **672** | **606** | **674** | **597** |
| **Development Projects*** | | | | | |
| Darlington Refurbishment Project*** | 1,249 | 1,231 | 1,127 | 947 | 1,129 |
| Ranney Falls GS Redevelopment** | 25 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 1 | 9 | 41 | 37 | 36 |
| Nanticoke Solar Project** | 6 | 103 | 0 | 0 | 0 |
| Calabogie GS Redevelopment** | 2 | 3 | 3 | 61 | 18 |
| Other Business Development | 28 | 28 | 69 | 62 | 49 |
| **Total Development Projects** | **1,311** | **1,410** | **1,253** | **1,107** | **1,233** |
| **Total Capital Expenditures** | **1,926** | **2,082** | **1,859** | **1,781** | **1,830** |

* While in definition phase, projects are budgeted by Corporate Business Development (within Finance) and, while in execution phase, projects are budgeted by Renewable Generaiton and other Support Services organizations

** Includes expenditures budgeted by Renewable Generation and Support Services

*** Includes expenditures budgeted by the Nuclear organization and Support Services

| Financing and Liquidity Outlook - Years Ended Dec 31 | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| ***Opening Cash Balance*** | **186** | **234** | **273** | **354** | **249** |
| **Net Operating Cash Inflows before the following:** | **1,723** | **2,227** | **3,070** | **2,646** | **3,113** |
| Earnings from Fair Hydro Trust (pre-tax) | 1 | 64 | 131 | 206 | 285 |
| Interest Paid (excl. Fair Hydro Trust) | (251) | (261) | (264) | (250) | (230) |
| Nuclear Funds Contribution | - | - | - | - | - |
| Pension Fund Contribution | (212) | (215) | (219) | (213) | (217) |
| OPEB Payments | (110) | (112) | (116) | (121) | (125) |
| Internally Funded Nuclear Provision Expenditures | (208) | (235) | (219) | (202) | (184) |
| **Net Cash from Operations** | **944** | **1,468** | **2,384** | **2,067** | **2,642** |
| **Investing Activities** | | | | | |
| Sustaining Capital Expenditures | (615) | (672) | (606) | (674) | (597) |
| Darlington Refurbishment | (1,249) | (1,231) | (1,127) | (947) | (1,129) |
| Ranney Falls GS Redevelopment | (25) | (35) | (13) | (0) | - |
| Sir Adam Beck Units 1 & 2 Conversion | (1) | (9) | (41) | (37) | (36) |
| Nanticoke Solar | (6) | (103) | (0) | (0) | (0) |
| Other Development | (30) | (32) | (72) | (123) | (68) |
| **Capital Expenditures** | **(1,926)** | **(2,082)** | **(1,859)** | **(1,781)** | **(1,830)** |
| Pre-tax Proceeds from Sale of 700 University Ave. Property | 484 | - | - | - | - |
| Pre-tax Proceeds from Sale of Lakeview Site | - | 267 | - | - | - |
| Acquisition of Fair Hydro Trust Assets | (1,179) | (2,326) | (2,557) | (2,812) | (2,741) |
| Proceeds from Deposit Note (Peter Sutherland Sr. GS) | 70 | - | - | - | - |
| Other | 73 | 16 | - | - | - |
| **Net Cash Outflow for Investing Activities** | **(2,478)** | **(4,125)** | **(4,416)** | **(4,593)** | **(4,571)** |
| **Financing Activities** | | | | | |
| General Corporate Debt - *Debt Issuance/Refinancing* | 1,301 | 1,191 | 128 | 365 | 200 |
| - *Debt Retirement* | (900) | (395) | (365) | (660) | (185) |
| Private Placement Debt - *Debt Issuance/Refinancing* | - | - | - | - | - |
| - *Debt Retirement* | (203) | (3) | (3) | (3) | (228) |
| Fair Hydro Trust Senior Debt - *Debt Issuance* | 601 | 1,184 | 1,302 | 1,432 | 1,397 |
| Short-Term Notes - *Net Issuance (Repayment)* | 260 | 200 | (50) | 75 | (385) |
| Issuance of Class A Shares | 519 | 1,022 | 1,123 | 1,235 | 1,206 |
| Dividends Paid | - | (482) | - | - | - |
| Distribution Paid to Non-Controlling Interests | (15) | (22) | (22) | (23) | (25) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - | - | - |
| **Net Cash from Financing Activities** | **1,582** | **2,695** | **2,113** | **2,422** | **1,980** |
| **Net Cash Inflow (Outflow) for Period** | **48** | **39** | **81** | **(105)** | **52** |
| ***Ending Cash Balance*** | ***234*** | ***273*** | ***354*** | ***249*** | ***301*** |
| ***Total OPG Debt*** | ***5,978*** | ***6,971*** | ***6,681*** | ***6,458*** | ***5,860*** |
| ***Fair Hydro Trust Senior Debt*** | ***601*** | ***1,786*** | ***3,088*** | ***4,519*** | ***5,917*** |
| ***Total Consolidated Debt*** | ***6,579*** | ***8,757*** | ***9,768*** | ***10,978*** | ***11,777*** |

## APPENDIX 4: NUCLEAR FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Nuclear | Actual | Business Plan | | | |
|---|---|---|---|---|---|
| *(in millions of dollars)* | 2017 | 2018 | 2019 | 2020 | 2021 |
| **OM&A** | | | | | |
| Base* | 1,254 | 1,251 | 1,276 | 1,294 | 1,298 |
| Outage Incremental | 314 | 334 | 246 | 336 | 116 |
| Project Portfolio | 123 | 91 | 82 | 82 | 87 |
| Pickering Extension Enabling Costs | 18 | 59 | 82 | 81 | 54 |
| Darlington Refurbishment Project | 36 | 23 | 3 | 38 | 23 |
| New Nuclear ** | 0 | 1 | 1 | 1 | 1 |
| **Total Nuclear OM&A** | **1,746** | **1,759** | **1,690** | **1,831** | **1,578** |
| **Capital** | | | | | |
| Project Portfolio*** | 357 | 384 | 353 | 289 | 244 |
| Darlington Refurbishment Project ** | 1,223 | 1,203 | 1,100 | 921 | 1,104 |
| **Total Nuclear Capital** | **1,580** | **1,588** | **1,453** | **1,211** | **1,348** |
| **Nuclear Waste Provision Expenditures** | **276** | **331** | **342** | **348** | **343** |
| **Fuel Expense** (Pickering and Darlington) | **225** | **226** | **236** | **202** | **201** |

* Includes an estimated $4M to $5M per year for work in support of the Renewable Generation business unit

** Excludes expenditures budgeted by Support Services

*** In 2019, includes $16M related to the load of new fuel bundles into the refurbished Darlington Unit 2

### Operational Targets

The key 2018-2020 targets for the Nuclear business unit are set out below. These targets reflect the operating environment of the nuclear fleet, including refurbishment activities at the Darlington station.

| | | | Pickering | | | | Darlington | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Metric | NPI Max | Industry Best Quartile | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target | Actual 2017 | 2018 Annual Target | 2019 Annual Target | 2020 Annual Target |
| All Injury Rate (#/200k hrs worked)[1] | N/A | 0.64 | 0.06 | 0.22 | 0.19 | 0.19 | 0.40 | 0.22 | 0.19 | 0.19 |
| Collective Radiation Exposure (person-rem/unit) | 80.00 | 45.33 | 74.36 | 110.30 | 83.40 | 126.10 | 93.56 | 79.80 | 80.00 | 79.00 |
| Unit Capability Factor (%) | 92.0 | 89.41 | 80.00 | 74.6 | 80.5 | 69.2 | 85.17 | 86.0 | 87.8 | 79.3 |
| Forced Loss Rate (%) | 1.00 | 1.49 | 5.18 | 3.50 | 3.50 | 3.50 | 1.72 | 1.00 | 1.00 | 4.28 |
| On-line Corrective Maintenance Backlog (work orders/unit) | N/A | 4 | 25 | 20 | 12 | 4 | 13 | 7 | 4 | 4 |
| WANO NPI (Index) | N/A | 96.9 | 76.7 | 75.5 | 76.7 | 75.5 | 82.0 | 91.3 | 91.7 | 88.1 |
| Human Performance Error Rate (# per 200k ISAR and contractor hrs) | N/A | 0.02 | 0.12 | 0.06 | 0.06 | 0.06 | 0.05 | 0.06 | 0.06 | 0.06 |
| Total Generating Cost per MWh[2] | N/A | $38.77 | 66.01 | 73.17 | 64.93 | 76.08 | 49.93 | 51.66 | 53.91 | 50.13 |

[1] All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

[2] Consistent with industry definition, metrics exclude centrally-held Pension and OPEB costs, asset service fees, and used fuel expenses. Targets may change subject to allocations and assumptions being finalized. Darlington metrics have been normalized for generation forgone during refurbishment. The non-normalized Darlington actual TGC for 2017 is $71.78/MWh, and the target for 2018 is $70.26/MWh, 2019 is $67.04/MWh, and 2020 is $74.26/MWh.

## APPENDIX 5: RENEWABLE GENERATION FINANCIAL PLAN AND OPERATIONAL TARGETS

### Financial Plan

| Renewable Generation<br>*(in millions of dollars)* | Actual<br>2017 | Business Plan<br>2018 | <br>2019 | <br>2020 | <br>2021 |
|---|---|---|---|---|---|
| **OM&A** | | | | | |
| Regulated Hydroelectric | 193 | 184 | 183 | 188 | 190 |
| Contracted Generation | 109 | 114 | 115 | 104 | 106 |
| Other* | 11 | 6 | 8 | 8 | 8 |
| **Total Base OM&A** | **313** | **305** | **306** | **300** | **304** |
| Regulated Hydroelectric | 42 | 71 | 77 | 73 | 90 |
| Contracted Generation | 14 | 18 | 12 | 15 | 10 |
| **Total Project OM&A** | **56** | **89** | **89** | **89** | **99** |
| Regulated Hydroelectric | 235 | 255 | 260 | 261 | 279 |
| Contracted Generation | 122 | 133 | 127 | 120 | 116 |
| Other | 11 | 6 | 8 | 8 | 8 |
| **Total Renewable Generation OM&A** | **368** | **394** | **395** | **389** | **404** |
| **Capital** | | | | | |
| Little Long Dam Safety Project | - | 6 | 34 | 149 | 98 |
| Sir Adam Beck Water Conveyance System Project | 3 | 8 | 7 | 20 | 90 |
| Other Sustaining | 155 | 185 | 156 | 136 | 125 |
| **Total Sustaining Capital** | **158** | **199** | **197** | **305** | **313** |
| Nanticoke Solar | 0 | 103 | 0 | - | - |
| Ranney Falls GS Redevelopment | 24 | 35 | 13 | 0 | - |
| Sir Adam Beck Units 1 & 2 Conversion | 0 | 9 | 41 | 37 | 36 |
| Other Development | 36 | 5 | - | - | - |
| **Total Development Capital** | **61** | **152** | **54** | **38** | **36** |
| **Total Renewable Generation Capital** | **219** | **351** | **251** | **343** | **349** |
| **Total Thermal Decommissioning Expenditures** | **23** | **28** | **56** | **74** | **21** |
| **Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | | | | | |
| Regulated Hydroelectric (net of SBG losses)** | 320 | 326 | 325 | 330 | 315 |
| Contracted Generation Portfolio | 54 | 54 | 52 | 55 | 56 |
| **Total Hydroelectric Gross Revenue Charge and Thermal Fuel Expense** | **374** | **380** | **378** | **385** | **370** |

*Includes an estimated $4M per year, in 2018-2021, for work in support of the Nuclear Organization

** Regulated hydroelectric GRC expenses assuming no SBG losses are: $320M in 2017, $360M in 2018, $359M in 2019, $349M in 2020, $331M in 2021.

## Operational Targets

The key 2018-2021 Renewable Generation targets designed to drive continuous performance are set out below.

| Renewable Generation | Actual 2017 | Business Plan 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|
| **All Injury Rate*** *(#/200k hrs worked)* | 2.05 | 1.23 | 1.06 | 1.03 | 1.03 |
| **Environment** *(#)* | | | | | |
| Category C Spills | 3 | 8 | 8 | 8 | 8 |
| Environmental Infractions | 1 | 7 | 6 | 6 | 6 |
| **Capacity** *(MW)* | 9,928 | 9,925 | 9,999 | 9,851 | 9,911 |
| Regulated Hydroelectric | 6,426 | 6,412 | 6,437 | 6,443 | 6,502 |
| Contracted Generation (Hydro, Thermal and Solar) | 3,500 | 3,512 | 3,560 | 3,407 | 3,407 |
| Wind | 1.8 | 1.8 | 1.8 | 1.8 | 1.8 |
| **Hydroelectric Availability** *(%)* | **86.5%** | **87.3%** | **87.4%** | **88.0%** | **85.6%** |
| Regulated Hydroelectric | 88.3% | 89.2% | 89.7% | 89.4% | 84.7% |
| Contracted Generation | 74.9% | 75.1% | 72.5% | 78.7% | 91.6% |
| **Hydroelectric Equivalent Forced Outage Rate** *(%)* | **3.1%** | **2.0%** | **1.8%** | **1.7%** | **1.7%** |
| Regulated Hydroelectric | 3.0% | 1.7% | 1.7% | 1.7% | 1.7% |
| Contracted Generation | 3.9% | 3.8% | 2.1% | 1.5% | 1.4% |
| **Thermal Equivalent Forced Outage Rate (Operating)** *(%)* | 2.4% | 5.1% | 5.1% | 5.1% | 5.1% |
| **Total Hydroelectric Generating Cost per MWh**** *($/MWh)* | 23.9 | 26.8 | 25.3 | 25.0 | 26.0 |

* All Injury Rate (AIR) has been replaced in 2018 with the Total Reportable Injury Frequency (TRIF). TRIF includes restricted work injuries which is expected to be minimal and as a result there is no change in targets set for AIR.

# Key Enterprise Level Initiatives

## Core Initiatives

- **OPG25**: The initiative is intended to address the cost structure implications of Pickering closure through the design and implementation of an optimal, cost effective organization for OPG. The initiative also seeks enterprise wide efficiency improvements and cost saving opportunities that will improve corporate profitability, support a culture of continuous improvement, and assist OPG in achieving industry-leading generation cost targets.
- **Darlington for the Future:** The initiative is closely integrated with the OPG25 initiative and seeks operational excellence to ensure industry-leading performance at Darlington post refurbishment. The initiative focusses on consistent achievement of nuclear generation production targets.
- **Equity Optimization**: The initiative is aimed at making balanced decisions going forward between the use of capital for growth investments and the payment of dividends to gradually transition the overall corporate equity thickness from existing ~65% level toward the OEB deemed level of 45%.
- **Building our Business**: OPG's strives to be a leader in the North American transition toward a low carbon future. This initiative focusses on maintaining and enhancing OPG's scale and energy industry leadership across carbon-friendly generation technologies, including potential extensions to OPG's business, investments in commercial innovation and asset acquisitions.

## Enabling Initiatives

- **One OPG Culture:** The initiative aims to foster cultural shifts where employees work together at all levels to achieve a greater sense of ownership, in an environment where information flows more freely. The cultural shift will facilitate building a diverse, well-trained, healthy, and engaged workforce committed to the long-term success of the Company and will drive greater alignment of leaders across the organization to achieve desired performance outcomes and behaviours.
- **Resourcing Strategy:** The initiative includes building a "One Company" approach to hiring by delivering a seamless end-to-end experience for new hires, redesigning existing business processes for talent resourcing, and continuing to enhance the updated leadership model to promote empowerment and personal leadership amongst employees.
- **Project Management Centre of Excellence:** The initiative promotes OPG's goal of being the best in the power industry at delivering all projects safely, with high quality, on time and on budget. With OPG continuing to invest significantly in projects over the next decade, the initiative aims to improve consistency of project outcomes through a common, scalable project delivery model, corporate-wide project management standards and services, and development of project management capability.
- **Digital Strategy:** The initiative seeks to enable OPG to achieve productivity improvements and capitalize on business optimization opportunities through technology investments. The initiative's goals include: increasing worker mobility, enhancing collaboration through people-share and networks, increasing automation to improve efficiency, and leveraging digital innovation to increase equipment reliability and reduce operating costs.
- **Regulatory Effectiveness:** The initiative seeks to continue to build more constructive, transparent, flexible and responsive relationships with the OEB and stakeholders, to improve OPG's culture as a regulated entity and deepen the understanding of the regulatory process across the Company, and to improve regulatory process efficiency by exploring opportunities to simplify the rate application process.
- **Relationships and Outreach:** The initiative focuses on developing and implementing an integrated stakeholder program and stakeholder engagement plans with a view to reinforcing OPG's social licence and strengthening the overall OPG brand, both externally and internally. The initiative recognizes the critical importance of respectful, trust-based relationships with communities, employees, stakeholders, regulators and Indigenous Peoples to OPG's social licence and overall success.

## Key Business Unit Initiatives

### Nuclear

- **Equipment Reliability:** The initiative aims to improve equipment reliability, improve efficiency of the maintenance program and reduce equipment failures to meet forced loss rate targets. A key driver in driving improved equipment reliability and station performance will be the implementation of the Monitoring and Diagnostic Centre. The collection and analysis of data will facilitate early detection of major/critical equipment degradation with the objective of reducing unplanned maintenance.
- **Outage Planning and Execution:** The initiative focuses on delivering predictable outage performance through improved planning and execution of outage work to meet planned outage duration targets.
- **Project Planning and Execution:** The initiative will drive effort in three key areas in order to improve project planning and execution and optimize investment decisions: Nuclear Project Management Office commitment to front end planning and Engineering Project Controls; stakeholder engagement in setting out the proper scope and clear expectations; and support for integrated asset management.
- **Innovation and Technology:** The initiative focuses on improvements in inspection tooling capability that will help to further operational efficiencies in order to meet outage schedules and generation requirements and reduce radiation exposure.
- **Strategic Asset Management:** The initiative focuses on early identification of project requirements and developing an optimized, integrated investment strategy through improved asset options, standard processes and increased oversight.

### Renewable Generation

- **Asset Value Enhancement:** The initiative targets adding 170 MW of incremental renewable generation capacity by 2021, including through the Ranney Falls GS and Nanticoke solar facility projects, frequency conversion of Sir Adam Beck I GS Units 1 & 2, and the runner upgrade program.
- **Innovation and Technology:** The initiative pursues innovation and technology-based improvements in asset management and equipment maintenance strategies. This includes leveraging the Monitoring and Diagnostic Centre concept to facilitate a move from preventative to condition-based maintenance and inform asset management decisions, and implementing digital work management to improve work flow efficiency and provide real-time updates on completed tasks.
- **Efficiency Improvement:** The initiative includes continuing to implement regionalization initiatives, control room consolidation, and work management and organizational realignment efficiencies across the fleet. It also includes developing contract management plans to ensure achievement of contract return on equity levels, as well as an assessment of Thunder Bay GS extension options.
- **Safety Performance Improvement:** The initiative involves a broad-based safety improvement plan that targets significant improvements in the Renewable Generation safety management system, including strengthening proactive reporting, enhancing linkage of embedded health and safety advisors with local senior management, internally and externally benchmarking safety best practices, and fostering a culture of personal leadership in safety.

### Corporate Support Services

- **Real Estate Security and Flexibility**: Chief Administrative Office (CAO) will negotiate a lease extension of 5 years at the General Motors building to support Darlington Refurbishment. CAO will also seek the flexibility to release OPG from existing lease obligations prior to the end of term.
- **Supply Chain Efficiencies:** CAO will continue to drive efficiencies through value improvement and inventory optimization, and will leverage the new Nuclear asset management tool across Supply Chain.
- **Generation Support Strategies**: Chief Information Office will support key business initiatives to improve the Company's generation facilities in such areas as the Monitoring and Diagnostic Centre, capital asset lifecycle portfolio management, equipment reliability improvement, field productivity and data integration and visualization.
- **Innovative Financial Strategies**: Finance will leverage the public debt program to provide financial

flexibility and optimize capital structure, facilitate growth through technology innovation and organic development, and pursue achievement of long-term target returns on the pension and nuclear segregated funds. Finance will also implement the Fair Hydro Trust to achieve targeted returns.

- **Talent, Succession, Training and Development**: People & Culture will lead processes and programs to ensure talent attraction, enable succession planning, foster a diverse and inclusive workforce, deliver high quality and cost effective training, build project management capabilities, and promote career development.
- **Brand Awareness:** Corporate Affairs will leverage strategic communications, earned and social media, advertising sponsorships and new Made in Ontario corporate reputation campaign to increase awareness of OPG's role in clean air/climate change, support of electrical vehicles and biodiversity initiatives. Engagement and awareness of OPG's site community support and the benefits of the Company's citizenship activities and Indigenous partnerships will also be strengthened.

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# OPG – 2017-19 Business Plan Fiscal Impact

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| **Income Tax PILs** | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **812** |
| **OPG 2017-19 Business Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 349 | 406* | 678 | 726 |
| **Income Tax PILs** | 96 | 166** | 135 | 170 |
| **Earnings Before Tax** | **445** | **572*** | **813** | **896** |
| **EBT Variance to Fiscal Plan** | (250) | (173)*** | (42) | 84 |

* Pre-tax gain on sale of OPG head office property of $296M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.
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- The current fiscal plan from Budget 2016, based primarily on OPG's 2015 Business Plan, as its board-approved 2016-18 multi-year business plan had not yet been approved and provided when the 2016 Budget fiscal plan was locked.
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| **OPG 2017-19 Business Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 349 | 479* | 678 | 726 |
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ORIGINAL FILE

w/o Head Office sale

Backed out

Delete

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Budget 20[illegible] Fiscal Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 471 | 586 | 673 | 705 |
| **Income Tax PILs** | [illegible] | 159 | 182 | 108 |
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| **OPG 2017-19 Business Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 379 | 480* | 678 | 726 |
| **Income Tax PILs** | 92 | 92** | 135 | 170 |
| **Earnings Before Tax** | **471** | **572*** | **813** | **896** |
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NOTE: Backing out OPG head office property sale and other sums may not may not add up due to rounding.

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# OPG – 2017-19 Business Plan Fiscal Impact

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ORIGINAL FILE

w/o Head Office sale

Backed out

Delete

| | | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Budget 2016 / Fiscal Plan ($M)** | | | | |
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| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Budget 2016 / Fiscal Plan ($M)** | | | | |
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| **Income Tax PILs** | 92 | 92** | 135 | 170 |
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  - The net income amount is adjusted to exclude the OPG head office properties amount, as it would be included under "Sales and Rentals", as it has been for previous Documents.
  - Note that the following is on OPG's U.S. GAAP basis of accounting, and does not show the consolidation adjustment for the nuclear funds, nor potential IFRS consolidation adjustments.
  - The OPG numbers in the table do not reflect any impact of the proposed Global Adjustment smoothing.
  - Note that OPG also pays property tax PILSs and Gross Revenue Charges, which tend to be very stable, by design, year-over-year.

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Budget 2016 / Fiscal Plan ($M)** | | | | |
| **Net Income After Tax ~~(Adjusted)~~** | 471 | 586 | 673 | 705 |
| **Income Tax PILs** | 224 | 159 | 182 | 108 |
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| **Net Income After Tax (Adjusted)** | 471 | 586 | 673 | 705 |
| **Income Tax PILs** | 437 | 382 | 414 | 343 |
| **Earnings Before Tax** | **908** | **968** | **1087** | **1,048** |
| **OPG 2017-19 Business Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 387* | 480** | 678 | 726 |
| **Income Tax PILs** | 302 | 315*** | 366 | 408 |
| **Earnings Before Tax** | **681** | **795** | **1,044** | **1,134** |
| **EBT Variance to Fiscal Plan** | (219) | (173) | (43) | 86 |

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*Includes ONFA adjustment of $8M
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# QUESTIONS TO OPG ABOUT THE 2018-2021 BUSINESS PLAN

Q1: On pg3 it it states approximately 4,000 staff will be impacted by a Pickering closure. It seems the current headcount for nuclear staff is approximately 6,100. Does this imply there's approximately 2,100 staff working at Darlington?

Q2: On pg3, it states that

*To end of 2017, $93 million has been spent on planning activities for Unit 3…*
Please confirm if these are ONLY for unit 3 or were there planning activities shared amongst preparation costs for all the other Units to be refurbished.

Q3: How has or will OPG's credit metrics be impacted by (borrowing for) the Fair Hydro Plan?

Q4: OPG noted the mandate set by the OEB to achieve collective agreements more in line with benchmarks. What kind of (job) action can be taken by PWU or SEP (if any), should agreements not be reached. Furthermore what kind of (job) action could happen to effect the Darlington Refurbishment Project? Can any of these actions affect the timing, scope, deliverables and costs of the refurbishment? Can actions affects contracts with suppliers and also affect timing, scope, deliverables and costs of the refurbishment or is refurbishment insulated from collective agreements.

Q5: On pg 4, the Business Plan lists growth opportunities through potential extensions to the business complementary to existing operations. Would the OEB view any of these 'complementary extensions' as related to existing regulated assets and in turn reduce the revenue requirements due to 'external revenue'?

Q6: Can you separate out the components of FHP EBT amounts. Some of the return comes from higher interest rates via the sub and jr. sub debt. However other portions of the return are from incentive and variable/performance fee mechanisms. Would OPG be able to help us distinguish these components? (This would be useful for modelling purposes should the interest rates change).

| ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| **EBT from Subordinated Debt** | | | | |
| **EBT from Jr. Subordinated Debt** | | | | |
| **EBT from other Debt (if applicable)** | | | | |
| **EBT from Incentive/Performance Fees** | | | | |
| **EBT from …(insert other FHP sources)** | | | | |
| **TOTAL – EBT FHP (pg 2)** | 10 | 80 | 150 | 225 |
| | | | | |
| **Income Tax (impact of FHP)** | | | | |
| **Net Income (impact of FHP)** | | | | |

*Modify or insert additional rows to provide accurate break down. Please feel free to modify above table.*

Q7: Would a projected financial statement of the Fair Hydro Trust be able to be provided? (Modelling purposes).

Q8: OPG filed a Notice of Motion to review and vary the Decisions in relations to the approval of the effective date of the recent rate decision of June 1, 2017 versus January 1, 2017 as requested in OPG's application. What would be the change to the proposed business plan's fiscal projection should the OEB agree to a January 1, 2017 effective date.

[Q8b: Furthermore, how would this impact any future corporate borrowing needs for OPG?]

**Corporate and Electricity Finance Division**
**February 27, 2018**

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| ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| EBT from Subordinated Debt | | | | |
| EBT from Jr. Subordinated Debt | | | | |
| EBT from other Debt (if applicable) | | | | |
| EBT from Incentive/Performance Fees | | | | |
| EBT from …(insert other FHP sources) | | | | |
| TOTAL – EBT FHP (pg 2) | 10 | 80 | 150 | 225 |
| | | | | |
| Income Tax (impact of FHP) | | | | |
| Net Income (impact of FHP) | | | | |

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Q9: On page 7, the last paragraph states that the retrospective revenue shortfall is $480M in 2017, and then in the first paragraph of page 9, it mentions forgone net income of $325M in 2017. Why are these 2 numbers different and how are they related?

Q10: How was the rate smoothing amount determined?

**Corporate and Electricity Finance Division**
**February 27, 2018**

**COMMERCIALLY SENSITIVE AND CONFIDENTIAL**

# QUESTIONS TO OPG ABOUT THE 2018-2021 BUSINESS PLAN

Q1: On pg3 it ~~it~~ states approximately 4,000 staff will be impacted by a Pickering closure. It seems the current headcount for nuclear staff is approximately 6,100 [state source]. The simple math of deducting 4000 from 6,100 likely is not the complete picture. Could additional details/information be provided on how the workforce numbers would be after the closure of Pickering. ~~Does this imply there's approximately 2,100 staff working at Darlington?~~

**Commented [JK1]:** We know 2,100 likely isn't the right number so putting this could be seen as aggressive, no?

Q2: On pg3, it states that

*To end of 2017, $93 million has been spent on planning activities for Unit 3…*
Please confirm if these are ONLY for unit 3 or were there planning activities shared amongst preparation costs for all the other Units to be refurbished.

Q3: How has or will OPG's credit metrics be impacted by (borrowing for) the Fair Hydro Plan?

Q4: OPG noted the mandate set by the OEB to achieve collective agreements more in line with benchmarks. What kind of (job) action can be taken by PWU or SEP (if any), should agreements not be reached. Furthermore what kind of (job) action could happen to ~~effect~~ affect the Darlington Refurbishment Project? Can any of these actions affect the timing, scope, deliverables and costs of the refurbishment? Can actions affect~~s~~ contracts with suppliers and also affect timing, scope, deliverables and costs of the refurbishment or is refurbishment insulated from collective agreements. [We could ask about their contingency planning – not 100%.]

Q5: On pg 4, the Business Plan lists growth opportunities through potential extensions to the business complementary to existing operations. Would the OEB view any of these 'complementary extensions' as related to existing regulated assets and in turn reduce the revenue requirements due to 'external revenue' or would these extensions be outside of the regulated segments of OPG's business?

Q6: Can you separate out the components of FHP EBT amounts. Some of the return comes from higher interest rates via the sub and jr. sub debt. However other portions of the return are from incentive and variable/performance fee mechanisms. Would OPG be able to help us distinguish these components? (This would be useful for modelling purposes should the interest rates change).

| ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|
| EBT from Subordinated Debt | | | | |
| EBT from Jr. Subordinated Debt | | | | |
| EBT from other Debt (if applicable) | | | | |
| EBT from Incentive/Performance Fees | | | | |
| EBT from …(insert other FHP sources) | | | | |
| TOTAL – EBT FHP (pg 2) | 10 | 80 | 150 | 225 |
| | | | | |
| Income Tax (impact of FHP) | | | | |
| Net Income (impact of FHP) | | | | |

*Please m~~M~~odify or insert additional rows to provide accurate break down. Please feel free to modify above table.*

Q7: Would a projected financial statement of the Fair Hydro Trust be able to be provided? (Modelling purposes).

**Commented [JK2]:** Not quite sure given the short history, how this would help.

Q8: OPG filed a Notice of Motion to review and vary the Decisions in relations to the approval of the effective date of the recent rate decision of June 1, 2017 versus January 1, 2017 as requested in OPG's application. What would be the change to the proposed business plan's fiscal projection should the OEB agree to a January 1, 2017 effective date.

[Q8b: Furthermore, how would this impact any future corporate borrowing needs for OPG?]

Q9: On page 7, the last paragraph states that the retrospective revenue shortfall is $480M in 2017, and then in the first paragraph of page 9, it mentions forgone net income of $325M in 2017. Why are these 2 numbers different and how are they related?

**Commented [JK3]:** Could one be NI and the other EBT?

Q10: How was the rate smoothing amount determined?

**Corporate and Electricity Finance Division**
**February 27, 2018**

**COMMERCIALLY SENSITIVE AND CONFIDENTIAL**

# QUESTIONS TO OPG ABOUT THE 2018-2021 BUSINESS PLAN

Q1: On pg3 it ~~-it~~ states approximately 4,000 staff will be impacted by a Pickering closure. It seems the current headcount for nuclear staff is approximately 6,~~100~~ 176 in 2017 and 6,171 in 2018 [~~state source~~pg 25 of BP PDF or pg 19 of the BP Document]. The simple math of deducting 4000 from 6,100 likely is not the complete picture. Could additional details/information be provided on how the workforce numbers would be after the closure of Pickering. ~~Does this imply there's approximately 2,100 staff working at Darlington?~~

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| ($M) | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
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| EBT from Incentive/Performance Fees | | | | |
| EBT from …(insert other FHP sources) | | | | |
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Q~~10~~9: How was the rate smoothing amount determined?

**Corporate and Electricity Finance Division**
**February 27, 2018**

**Commented [JK2]:** Not quite sure given the short history, how this would help.

**Commented [SK3R2]:** If we get a hold of the projections, it might help us understand what the costs and fees for the FHT are and how to account for those in our own projections. Happy to remove otherwise.

**Commented [JK4]:** Could one be NI and the other EBT?

DRAFT

# OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

# OPG Fiscal Impact

- The table below illustrates OPG's fiscal impacts in the 2017 Budget forecast.

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|---|
| **OPG Net Income - 2017 Ontario Budget / Fiscal Plan** | | | | | |
| *OPG 2017-19 Business Plan*[1] | 349 | 702 | 678 | 726 | 913[1] |
| *OPG Monthly Shareholder Update (February 2017)* | 30 | | | | |
| *OPG IFRS Consolidation Risk*[2] | (75) | (400) | - | (200) | - |
| *OPG Head Office Sales (Reported under Sales and Rentals)*[3] | | (222) | | | |
| *GA Refinancing – OPG Trust Interest Revenue* | | 17 | 54 | 99 | 153 |
| ***OPG Net Income (After Tax, Adjusted)*** | **304** | **97** | **732** | **625** | **1,066** |
| *ONFA Adjustments*[4] | 8 | - | - | - | - |
| **OPG Income Tax PILs - 2017 Ontario Budget / Fiscal Plan** | | | | | |
| *OPG 2017-19 Business Plan* | 96 | 166 | 135 | 170 | 298[1] |
| *OPG Monthly Shareholder Update (February 2017)* | (4) | | | | |
| *OPG Head Office Sales (Reported under Sales and Rentals)*[3] | | (74) | | | |
| ***OPG Income Tax PILs (Adjusted)*** | 92 | 92 | 135 | 170 | 298 |

1 Fiscalized projection from OPG Business Plan

2 IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.

3 For public Budget reporting, projected net impacts of Province asset optimization strategy including, OPG Head Office sale, are reported under Sales and Rentals for commercial confidentiality. OPG proceeds estimate updated per 2017 Budget.

4 Provincial consolidation adjustments for unrealized earnings on decommissioning and used fuel segregated funds net of Bruce variance account and change in Due to the Province on the decommissioning and used fuel segregated funds.

DRAFT

# Updated OPG Fiscal Impacts

- The table below illustrates updated OPG's net income, income tax PILs and ONFA adjustment figures from the 2017 Budget forecast.

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|---|
| **Other updates since Budget 2017** | | | | | |
| *March 2017 Shareholder Update: OPG Net Income* | 385 | - | - | - | - |
| *March 2017 Shareholder Update: Income Tax Expense* | 94 | - | - | - | - |
| *ONFA Adjustments (as at Mar 31, 2017)* | 49 | - | - | - | - |

# Risks

- **OEB Risks:** OPG's multi-year rate application to the Ontario Energy Board for the period starting January 1, 2017, is currently in process. Potential OEB decisions providing for lower rates, including disallowance of recovery of OPG's operating costs, current or future deferral and variance account balances (including for the proposed nuclear rate smoothing) and unfavourable future treatment of pension costs would adversely affect OPG's results, resulting in negative fiscal impacts.
- **IFRS Risks:** A change in the basis of accounting used for consolidation of OPG results from U.S. GAAP to International Financial Reporting Standards (IFRS) on the Province's financial statements is expected to result in potentially significant fiscal impacts.

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| *Net additional OPG IFRS Consolidation Risks* | - | (25) | (525) | (475) |

- **Financing Costs:** Higher cost public capital market borrowing (vs the Province's borrowing cost for OEFC to lend to OPG) would have a negative fiscal impact.

# Risks – Darlington Refurbishment

- **Darlington Refurbishment Risk:** Darlington Refurbishment is executed consistent with the approved project budget and schedule. Failure to maintain cost and schedule commitments for the project could potentially result in significant write-offs against net income as well as reputational damage. In addition, inability to carry out the refurbishment of the first unit as planned may result in the Province of Ontario (Province) not proceeding with OPG's refurbishment of the remaining units.

# Electricity Sector Rules of Thumb

- **OPG Rule of Thumb**: For every $50M change in OPG revenues due to changes in regulated prices, all-in rate impact of about 0.04 ¢/kWh (less than 0.25% of total bill)

| OPG Risks | Fiscal Impact |
|---|---|
| Realised gains in ONFA funds v plan -/+ 1% | -/+ $100 million |
| Change in Regulated Prices -/+ 1% | -/+ $40 million |
| Regulated ROE -/+ 1% | -/+ $45 million |
| Nuclear regulated price -/+ 0.1 ¢/kWh | -/+ $40 million |
| Hydro regulated price -/+ 0.1 ¢/kWh | -/+ $20 million |
| Nuclear output -/+ 1 TWh | -/+ $70 million |
| Hydro output -/+ 1 TWh | -/+ $45 million |

DRAFT

# OPG Fiscal Impacts

Corporate and Electricity Finance Division
2017-05-01

DRAFT

# OPG Fiscal Impact

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DRAFT

# OPG Fiscal Impact Changes

- The table below illustrates OPG's fiscal impact variances in the 2017 Budget vs 2016 Budget.

| OPG Net Income and Income tax ($ Millions) | | | | |
|---|---|---|---|---|
| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
| **2016 Budget[1]** | | | | |
| Net Income | 471 | 586 | 673 | |
| Income Tax | 224 | 159 | 182 | |
| **2017 Budget** | | | | |
| Net Income 2017 Budget | 312 | 97 | 732 | 625 |
| Income tax 2017 Budget | 92 | 92 | 135 | 170 |
| **2016 Budget vs. 2017 Budget (including IFRS and sales & rental adjustments)** | | | | |
| Net Income | -167 | -489 | 59 | |
| Income taxes | -132 | -67 | -47 | |
| **2016 Budget vs. 2017 Budget (Before IFRS and sales & rental adjustments)** | | | | |
| Net Income | -84 | 133 | 59 | 200 |
| Income taxes | -132 | 7 | -47 | 0 |

1. 2016 Budget fiscal plan was largely based on OPG's 2015 multi-year business plan, as the 2016 multi-year business plan was approved and submitted following the timeframe for locking the numbers for the early 2016 Budget.
2. OPG February 2017 Monthly Update
3. IFRS risk is related to Province's reporting of nuclear asset retirement obligations. The Ontario Auditor General recommended (2016 AG Report) that the Province include Hydro One and OPG financial information in the consolidated financial statements using the IFRS reporting framework as required by PSAB standards, versus the companies U.S. GAAP basis of reporting.
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DRAFT

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# OPG 2017-19 Business Plan Questions

**Q: What are the explanation for EBT variances between 2016~~5~~ budget forecast, 2016-18 business plan forecast, and 2017-19~~6~~ business plan forecast?**

| Budget 2016~~5~~ ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax ~~(Adjusted)~~ | 471 | 586 | 673 | 705 |
| Income Taxes | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **813** |

| OPG ~~March~~ 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax ~~(Adjusted)~~ | ~~N/A~~302 | ~~N/A~~694 | 686~~N/A~~ |
| Income Taxes | 104~~N/A~~ | 245~~N/A~~ | 155~~N/A~~ |
| **Earnings Before Tax** | **406** | **939** | **841** |
| ~~**EBT Variance to Fiscal Plan**~~ | ~~**(289)**~~ | ~~**194**~~ | ~~**(14)**~~ |

| OPG 2017-19 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income Attributable to Shareholder | 349 | 702 | 678 | 726 |
| Income Tax PILs | 96 | 166 | 135 | 170 |
| **Earnings Before Tax** | **445** | **868** | **813** | **896** |

**Q: ~~Please provide the financial model corresponding to the 2016 Business Plan. What are the expected net income, income tax, and EBT, under the new business plan, for fiscal years 2015-2021? Do the forecast assume Pickering GS will be operating until 2024?~~ Can you also provide ~~new forecasts~~the breakdown of GRC, Proxy Property Tax, and Ontario Capital Tax for fiscal years 2016~~5~~-2020~~1~~ based on OPG's 2017-19~~6~~ business plan?**

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | | | | |
| ~~Income Taxes~~ | | | | |
| ~~Earnings Before Tax~~ | | | | |
| Non Income Tax PILs | | | | |
| GRC: Payable to OEFC | | | | |
| GRC: Payable to NPC | | | | |
| ~~Proxy~~ Property Tax Payable to OEFC | | | | |
| Total | | | | |
| | | | | |
| Income Tax~~Ontario Capital Tax~~ | | | | |
| Current Income Tax Payable | | | | |
| Increase/(Decrease) in Future Income Tax Liability | | | | |
| Income Taxes Payable to Ratepayers | | | | |
| Total | | | | |

**~~Q: The EBT forecasts in OPG's new business plan is $186M, $49M and $126M higher respectively in 2016-17, 2017-18, and 2018-19 than the preliminary forecasts provided in January. What explains the variance? The deck indicates that OPG included new particulars, assumptions, and strategies in the Business Plan, could these assumptions be provided?~~**

| ~~OPG's January Preliminary Planning Projections ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~300~~ | ~~100~~ | ~~640~~ | ~~575~~ |
| ~~Income Taxes~~ | ~~89~~ | ~~120~~ | ~~250~~ | ~~140~~ |
| ~~Earnings Before Tax~~ | ~~389~~ | ~~220~~ | ~~890~~ | ~~715~~ |

| ~~OPG March 2016 Business Plan ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ |
| ~~Income Taxes~~ | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ | ~~N/A~~ |
| ~~Earnings Before Tax~~ | ~~383~~ | ~~406~~ | ~~939~~ | ~~841~~ |

**Q: The 2016-17 Earnings Before Tax (EBT) in OPG's January projection drops $475M dollars from Budget 2015 forecast. What factors/risks were reflected in this forecast? Could the $475M be allocated to the various factors/risks quantitatively?**

| Budget 2015 ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 245 | 471 | 586 | 673 |
| Income Taxes | 100 | 224 | 159 | 182 |
| **Earnings Before Tax** | **345** | **695** | **745** | **855** |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 | 575 |
| Income Taxes | 89 | 120 | 250 | 140 |
| **Earnings Before Tax** | **389** | **220** | **890** | **715** |
| **EBT Variance to Fiscal Plan** | **65** | **(475)** | **145** | **(140)** |

## Liquidity and Funding

**Q: OPG projects to borrow $350 million in 2016? Is this still the latest borrowing need for 2016, and could OPG provide the latest borrowing needs for 2017-2018 as well?**

## OPG Business Plan – MOE Deck

**Q: OPG is planning to reduce total headcount from 9,302 in 2016 to 8,811 in 2021. Based on the news release, those refurbishment projects will provide for thousands of jobs. Does the headcount projection, i.e. the reduction, account for refurbishment projects, as well as the end of life extension for Pickering?**

**Q: We understand that headcount reduction plays an important role in improving OPG's efficiencies, are there any other initiatives or efforts that OPG is working on to improve efficiency?**

## OPG Business Plan in general

**Q #1: What OEB rate is used in this business plan? On page 2 of the business plan, it says that OEB's decision has been delayed to 3rd quarter of 2017, so "the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016/17 fiscal year." And on page 3, in the second bullet point, it says "the 2017-19 Business Plan assumes that new regulated rates from the application process are effective at the start of 2017." It's unclear if OPG's net income attributable to shareholder is based on the new rates or the old rates.**

**Q #26: Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "The OEB's decision on OPG's rate application is expected during the third quarter of 2017." – Even though the decision comes in late 2017, can OEB back date the effective date?**

**Q #3: When will next unit of the DRP start and how will that impact OPG's financial performance?**

**Q #4: Could you provide a financial summary of the OPG head office sale? What is the PIL expense without headquarter sales gain? Is there a PILs element in the $166M PIL number provided related to the headquarter sale?**

~~**Q: Can OPG provide a residential bill impact beyond 2021?**~~

**Q #54: Page 1-2 or Appendix 3:**

a) **The March 31, 2017 Fiscal NI Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.**
b) **Page 1 shows the 2016 Forecast of NI Attributable to Shareholder to be $438M. This is Jan 1, 2016 to Dec 31, 2016.**
c) **We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?**

~~**Q #5: What is the PIL expense without headquarter sales gain? Is there a PILs element in the $166M PIL number provided related to the headquarter sale?**~~

~~**Q #6: Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "The OEB's decision on OPG's rate application is expected during the third quarter of 2017." – Even though the decision comes in late 2017, can OEB back date the effective date?**~~

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| Income Taxes | 224 | 159 | 182 | 108 |
| **Earnings Before Tax** | **695** | **745** | **855** | **813** |

**Commented [j1]:** OPG would have no idea what we put into the Budget 2016 and why. Let's delete references to Budget 2016.

| OPG ~~March~~ 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax ~~(Adjusted)~~ | ~~N/A~~302 | ~~N/A~~694 | 686~~N/A~~ |
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| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|

| | | | | |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | | | | |
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| Non Income Tax PILs | | | | |
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| ~~Proxy~~ Property Tax Payable to OEFC | | | | |
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| ~~OPG March 2016 Business Plan ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
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## Liquidity and Funding

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## OPG Business Plan – MOE Deck

**Q: OPG is planning to reduce total headcount from 9,302 in 2016 to 8,811 in 2021. Based on the news release, those refurbishment projects will provide for thousands of jobs. Does the headcount projection, i.e. the reduction, account for refurbishment projects, as well as the end-of-life extension for Pickering?**

**Q: We understand that headcount reduction plays an important role in improving OPG's efficiencies, are there any other initiatives or efforts that OPG is working on to improve efficiency?**

## OPG Business Plan in general

Q #1: What OEB rate is used in this business plan? On page 2 of the business plan, it says that OEB's decision has been delayed to 3rd quarter of 2017, so "the outcome of the new rate application will not be known in time to be reflected in OPG's results that will be consolidated with the Province's 2016/17 fiscal year." And on page 3, in the second bullet point, it says "the 2017-19 Business Plan assumes that new regulated rates from the application process are effective at the start of 2017." It's unclear if OPG's net income attributable to shareholder is based on the new rates or the old rates.

Q #26: Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "The OEB's decision on OPG's rate application is expected during the third quarter of 2017." – Even though the decision comes in late 2017, can OEB back date the effective date?

Q #3: When will next unit of the DRP start and how will that impact OPG's financial performance?

Q #4: Could you provide a financial summary of the OPG head office sale? What is the PIL expense without headquarter sales gain? Is there a PILs element in the $166M PIL number provided related to the headquarter sale?

~~Q: Can OPG provide a residential bill impact beyond 2021?~~

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**Q #54: Page 1-2 or Appendix 3:**

a) **The March 31, 2017 Fiscal NI Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.**
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c) **We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?**

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# OPG 2017-19 Business Plan Questions

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| OPG ~~March~~ 2016-18 Business Plan ($M) | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income After Tax ~~(Adjusted)~~ | ~~N/A~~302 | ~~N/A~~694 | 686~~N/A~~ |
| Income Taxes | 104~~N/A~~ | 245~~N/A~~ | 155~~N/A~~ |
| **Earnings Before Tax** | **406** | **939** | **841** |
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## OPG Business Plan – MOE Deck

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# OPG 2017-19 Business Plan Questions

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| ~~**Earnings Before Tax**~~ | | | | |
| Non Income Tax PILs | | | | |
| GRC: Payable to OEFC | | | | |
| GRC: Payable to NPC | | | | |
| ~~Proxy~~ Property Tax Payable to OEFC | 15 | 18 | 19 | 19 |
| Total | 336 | 350 | 363 | 362 |
| | | | | |
| Income Tax [This section is intended to gain insight into the current vs. future taxes, as well as taxes for regulatory purposes.]~~Ontario Capital Tax~~ | | | | |
| Current Income Tax Payable | | | | |
| Increase/(Decrease) in Future Income Tax Liability | | | | |
| Income Taxes Payable to Ratepayers | | | | |
| Total | 96 | 166 | 135 | 170 |

**Commented [j4]:** Let's provide the total figure they have to lead them on.

**Commented [GH5R4]:** Updated.

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~~**Q: The EBT forecasts in OPG's new business plan is $186M, $49M and $126M higher respectively in 2016-17, 2017-18, and 2018-19 than the preliminary forecasts provided in January. What explains the variance? The deck indicates that OPG included new particulars, assumptions, and strategies in the Business Plan, could these assumptions be provided?**~~

| ~~OPG's January Preliminary Planning Projections ($M)~~ | ~~2015-16~~ | ~~2016-17~~ | ~~2017-18~~ | ~~2018-19~~ |
|---|---|---|---|---|
| ~~Net Income After Tax (Adjusted)~~ | ~~300~~ | ~~100~~ | ~~640~~ | ~~575~~ |
| ~~Income Taxes~~ | ~~89~~ | ~~120~~ | ~~250~~ | ~~140~~ |
| ~~**Earnings Before Tax**~~ | ~~**289**~~ | ~~**220**~~ | ~~**890**~~ | ~~**715**~~ |

| OPG March 2016 Business Plan ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | N/A | N/A | N/A | N/A |
| Income Taxes | N/A | N/A | N/A | N/A |
| **Earnings Before Tax** | **383** | **406** | **939** | **841** |

**Q: The 2016-17 Earnings Before Tax (EBT) in OPG's January projection drops $475M dollars from Budget 2015 forecast. What factors/risks were reflected in this forecast? Could the $475M be allocated to the various factors/risks quantitatively?**

| Budget 2015 ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 245 | 471 | 586 | 673 |
| Income Taxes | 100 | 224 | 159 | 182 |
| **Earnings Before Tax** | **345** | **695** | **745** | **855** |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 | 575 |
| Income Taxes | 89 | 120 | 250 | 140 |
| **Earnings Before Tax** | **389** | **220** | **890** | **715** |
| **EBT Variance to Fiscal Plan** | **65** | **(475)** | **145** | **(140)** |

## Liquidity and Funding

**Q: OPG projects to borrow $350 million in 2016? Is this still the latest borrowing need for 2016, and could OPG provide the latest borrowing needs for 2017-2018 as well?**

## OPG Business Plan – MOF Deck

~~Q: OPG is planning to reduce total headcount from 9,302 in 2016 to 8,811 in 2021. Based on the news release, those refurbishment projects will provide for thousands of jobs. Does the headcount projection, i.e. the reduction, account for refurbishment projects, as well as the end of life extension for Pickering?~~

~~Q: We understand that headcount reduction plays an important role in improving OPG's efficiencies, are there any other initiatives or efforts that OPG is working on to improve efficiency?~~

## OPG Business Plan in general

Q-3~~#16~~: Page 3 of BP: Delay in Effective Date: OPG 2017 BP assumes effective date of OPG's Rates is January 1, 2017 and there is a cost of $60 million per month to OPG's Net Income for the 2017/18 fiscal year if the effective date is a later date. Page 6 states "~~The~~ OEB's decision on OPG's rate application is expected during the third quarter of 2017." ~~– Even though the decision comes in late 2017, can OEB back date the effective date?~~ Is it your current outlook that OEB's decision would still be retroactive to January 1, 2017?

**Commented [j6]:** I'd think that it means the 2017-18 results will reflect the new rates effective back to Jan 1, 2017.

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**Commented [j7]:** It means that they'd likely get rate riders to recover the late implementation date.

Q4 ~~#2~~: C~~an~~ould you provide the financing requirements for the Darlington Refurbishment Project separately from other borrowing requirements?

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**Commented [j8]:** Just wondering what the reason behind the question is. Is it to get at the NI and PILs number impacts above?

**Commented [GH9R8]:** I revised this question. I think it would be nice to have their projected financing requirement for the DRP.

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~~Q: Can OPG provide a residential bill impact beyond 2021?~~

**Q5 ~~#24~~: Page 1-2 or Appendix 3:**

a) **The March 31, 2017 Fiscal Net Income Attributable to Shareholder is $349M. This is April 1, 2016 to March 31, 2017.**
b) **Page 1 shows the 2016 Forecast of NI Attributable to Shareholder to be $438M. This is Jan 1, 2016 to Dec 31, 2016.**
c) **We know OPG Q1 number was $123M, leaving $315M for the April 1, 2016 to December 31, 2016. With (a) above, is OPG forecasting approximately $34M for Q1 2017 (Jan 1, 2017 to March 31, 2017)?**

~~Q #5: What is the PIL expense without headquarter sales gain? Is there a PILs element in the $166M PIL number provided related to the headquarter sale?~~

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**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

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## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over 475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
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- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

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They also mention in the business plan on page 18:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

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- The OEB decision with respect to the Motion to Review ~~s to come in the future related to the items mentioned above, with respect to OPG's rate application including, the effective date for new rates, the revenue requirement request, and proposed rate smoothing,~~ would affect OPG's longer term liquidity outlook.

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  - In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
  (Note – numbers are subject to rounding)

**(REFER TO PG. 41 of OPG Business Plan for this chart…did a yearly projection update since we don't have monthly information anymore)**

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |

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**Commented [EJ4]:** OPG Q4 2017 pg. 2 of pdf

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Thought we should mention the Fair hydro plan info in the note since the chart below will have values related to the FHTrust. But unsure how much detail we need to give

| | | | |
|---|---|---|---|
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Proceeds of Distribution to Trillium Trust*** | - | - | - |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.

Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

**Commented [EJ7]:** We always seem to have taken the "General Corporate Debt" number from the monthly OPG pdf's but don't know if taking the whole number and categorizing it as New Debt to OEFC is accurate.

Referring to pg. 130 of OPG q4 2017 debt to OEFC adds up to 800M and OPG also issued Medium Term Note (not to OEFC) of 500M. So maybe this line should actually have 800M and we should have another line as "Additional Corporate Debt" and put 501M in it?

**Commented [EJ8]:** This row was added

**Commented [EJ9]:** New row added

**Commented [EJ10]:** Does not seem to be included in the cashflow statement?

**Commented [EJ11]:** New row added

**Commented [EJ12]:** Pg. 156 of OPG Q4 2017

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

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**Commented [EJ7R6]:** Reworded.

**Commented [EJ8]:** Add any additional updates per second issue

**Commented [EJ9]:** OPG Q4 2017 pg. 2 of pdf

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| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends (Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and additional corporate debt was approximately $500M.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.
Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

**Commented [EJ10]:** We always seem to have taken the "General Corporate Debt" number from the monthly OPG pdf's but don't know if taking the whole number and categorizing it as New Debt to OEFC is accurate.

Referring to pg. 130 of OPG q4 2017 debt to OEFC adds up to 800M and OPG also issued Medium Term Note (not to OEFC) of 500M. So maybe this line should actually have 800M and we should have another line as "Additional Corporate Debt" and put 501M in it?

**Commented [EJ11]:** This row was added

**Commented [EJ12]:** New row added

**Commented [EJ13]:** New row added

**Commented [EJ14]:** Requesting SIFB to check this line and the footnote below

**Commented [EJ15]:** Check if it should be 501M exact

**Commented [EJ16]:** Pg. 156 of OPG Q4 2017

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

**Commented [EJ1]:** Pg 53 of pdf of opg q4

**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18 of pdf:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

- The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, ~~I~~in December 2017~~,~~ the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

**Commented [EJ3]:** Add any additional updates per second issue (maybe Gavin/Shajee has more info)

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
(Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |

| | | | |
|---|---|---|---|
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends /Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
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* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and additional corporate debt was approximately $500M.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 ~~million~~M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

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Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Commented [EJ5R4]:** Confirmed 500M as principal amount in the prospectus documents

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**Background**

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| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
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| Jul 22, 2020 | 4.658 | 35 |
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| Oct 22, 2021 | 3.985 | 60 |
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| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
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| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
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| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
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| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

**Commented [EJ1]:** Pg 53 of pdf of opg q4

**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million ~~related to the June~~ 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an ~~. OPG has presented their arguments in oral~~a hearing ~~in~~ to present their arguments occurred ~~April~~on April 2017. This ~~and this~~ case is still currently ~~ongoing~~being reviewed by the OEB.

- The OEB decision with respect to the Motion to Review ~~s to come in the future related to the items mentioned above, with respect to OPG's rate application including, the effective date for new rates, the revenue requirement request, and proposed rate smoothing,~~ would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, ~~I~~in December 2017~~,~~ the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator (IESO) in the amount of approximately $1.2 billion. The Province funded 44% of the asset purchase, through OFA, for an amount of $519 million and subscribed for 12,217,616 Class A shares of OPG. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

  - On March 22, 2018, OPG purchased $460 million investment asset from the IESO. The Province funded 44% of the asset purchase, through OFA, for an amount of $202 million and subscribed for 4,627,343 Class A shares of OPG.

  - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

  - On April 20, 2018, OPG purchased $149 million investment asset from the IESO. The Province funded 44% of the asset purchase, through OFA, for an amount of $66 million and subscribed for 1,498,856 Class A shares of OPG.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
  (Note – numbers are subject to rounding)

**Commented [BA3]:** Is that number from OPG Q4?

**Commented [EJ4R3]:** Yes it was in their Q4 (pg. 2 of pdf)

**Commented [EJ5]:** OPG Q4 2017 pg. 2 of pdf

**Commented [BA6]:** I think OPG arguments originally presented in the January Motion to Review.

**Commented [EJ7R6]:** Reworded.

**Commented [EJ8]:** Add any additional updates per second issue

**Commented [EJ9]:** OPG Q4 2017 pg. 2 of pdf

Thought we should mention the Fair hydro plan info in the note since the chart below will have values related to the FHTrust. But unsure how much detail we need to give

**(REFER TO PG. 41 of OPG Business Plan for this chart…did a yearly projection update since we don't have monthly information anymore)**

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends (Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and additional corporate debt was approximately $500M.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.
Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Commented [EJ11]:** This row was added

**Commented [EJ12]:** New row added

**Commented [EJ13]:** New row added

**Commented [EJ14]:** Requesting SIFB to check this line and the footnote below

**Commented [EJ15]:** Check if it should be 501M exact

**Commented [EJ16]:** Pg. 156 of OPG Q4 2017

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.

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- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.
    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.
    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.
    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.
    - The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.
- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:
    - As reported in OPG's Q4 2017 Financial Statement, ~~I~~in December 2017~~,~~ the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.
- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |

**Commented [EJ3]:** Add any additional updates per second issue (maybe Gavin/Shajee has more info)

| | | | |
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| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
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| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
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| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

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**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18 of pdf:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

- The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, ~~I~~in December 2017~~,~~ the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

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- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
(Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |

| | | | |
|---|---|---|---|
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends /Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 ~~million~~M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.

Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as finsert rationale – per SIFB~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
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| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
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**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
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**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

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**OEFC Board Meeting – April 27, 2018**

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- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
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    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. ~~As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility.~~ The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board

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(OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

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- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
(Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
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| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |

| | | | |
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| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends (Proceeds of Distribution to Trillium Trust***) | - | ~~(482)~~ | ~~(482)~~ |
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| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 ~~million~~M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.

Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as finsert rationale – per SIFB~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018~~December 5~~, 2017):**

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| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Oct 22, 2017~~ | ~~5.47~~ | ~~50~~ |
| ~~Jan 22, 2018~~ | ~~5.218~~ | ~~75~~ |
| ~~Mar 22, 2018~~ | ~~5.09~~ | ~~200~~ |
| ~~Apr 22, 2018~~ | ~~5.424~~ | ~~50~~ |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470~~245~~.0** |

**Status of Project Financing (at April 23~~December 5~~, 2018~~7~~):**

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| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,4~~8~~00 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April ~~20~~23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

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**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18 of pdf:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

- The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, ~~I~~in December 2017~~,~~ the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

  - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million ~~investment asset from the IESO. The Province funded 44% of the asset purchase, through OFA, for an amount of $202 million and subscribed for 4,627,343 Class A shares of OPG.~~

  - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

  - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million ~~investment asset from the IESO. The Province funded 44% of the asset purchase, through OFA, for an amount of $66 million and subscribed for 1,498,856 Class A shares of OPG.~~

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
  (Note – numbers are subject to rounding)

**Commented [EJ3]:** Add any additional updates per second issue (maybe Gavin/Shajee has more info)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends (Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

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Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 as ~~[insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Background**

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| Timing | Action | Details |
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| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
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| Mar 22, 2018 | 5.09 | 200 |
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| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
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| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board

(OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

  - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

  - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

  - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

  - The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

  - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

  - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

  - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | ~~-~~(70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484)~~-~~ | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | ~~-~~(19) | - |
| Dividends ~~/~~(Proceeds of Distribution to Trillium Trust***) | ~~-~~ | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.

Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as finsert rationale – per SIFB~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – April 27, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - The OEB decision with respect to the Motion to Review would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
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| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at April 23, 2018, 2017):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – April 27, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - An amended ~~The~~ OEB decision with respect to the Motion to Review cw~~ould~~ould affect OPG's longer term liquidity outlook and net income related to the January 1, 2017 to May 31, 2017 period.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at April 23, 2018, 2017):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
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| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – April 27, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
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    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

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    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
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| Cash from Operations | 944 | 524 | 1,468 |
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| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
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| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at April 23, 2018, 2017):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected a $273 million in cash at the end of 2018.
    - As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 20187-202119 Business Plan, OPG is expected to spentd $1,249152 million in 2017 and projects to spend $1,231113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

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- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income related to the January 1, 2017 to May 31, 2017 period.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province.

Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
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| Apr 22, 2022 | 3.521 | 35 |
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| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected ~~a~~ $273 million in cash at the end of 2018.
  - As of December 31, 2017, OPG had a cash position of $234 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - ~~o~~ In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The~~e~~at Business Plan projected~~s~~ a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount~~change~~, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

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- In the 2018~~7~~-2021~~9~~ Business Plan, OPG ~~is expected to~~ spent~~d~~ $1,249~~152~~ million in 2017 and projects to spend $1,231~~113~~ million in 2018 on the Darlington Refurbishment project.

- ~~In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2019.~~

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, ~~they~~it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued ~~their~~its decision in December 2017, and ~~their~~its decision determined that new prices would be applied with an effective date of June 1, 2017.

  - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

  - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

  - In January 2018, OPG ~~has~~ filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is ~~still~~ currently being reviewed by the OEB.

  - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income ~~related to the January 1, 2017 to May 31, 2017 period~~.

- OPG ~~has been~~was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

**Commented [JK1]:** Would it be OK to use the latest BP?

**Commented [RK2]:** But not compared to the 2017-19 Business Plan, was it?

**Commented [RK3]:** Makes it sounds as if there would be a restatement. Is that the case?

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.
- On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038.
- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
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| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
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| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
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| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
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* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and

in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

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The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected ~~a~~ $273 million in cash at the end of 2018.
  - As of December 31, 2017, OPG had a cash position of $234 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - ~~o~~ In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The~~e~~at Business Plan projected~~s~~ a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount~~change~~, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

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- In the 20187-202119 Business Plan, OPG ~~is expected to~~ spent~~d~~ $1,249~~152~~ million in 2017 and projects to spend $1,231~~113~~ million in 2018 on the Darlington Refurbishment project.

~~- In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.~~

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, ~~they~~it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued ~~their~~its decision in December 2017, and ~~their~~its decision determined that new prices would be applied with an effective date of June 1, 2017.

  - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

  - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

  - In January 2018, OPG ~~has~~ filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is ~~still~~ currently being reviewed by the OEB.

  - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income ~~related to the January 1, 2017 to May 31, 2017 period~~.

- OPG ~~has been~~was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.~~2~~18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million ~~of~~ in senior notes payable, $382 million in

**Commented [JK1]:** Would it be OK to use the latest BP?

**Commented [RK2]:** But not compared to the 2017-19 Business Plan, was it?

**Commented [JK3R2]:** No, it is related to the new rates being effective.

**Commented [RK4]:** Makes it sounds as if there would be a restatement. Is that the case?

**Commented [JK5R4]:** I don't believe restatement is likely.

subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.
- On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.
- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |

| | | | |
|---|---|---|---|
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

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The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
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| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
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| Timing | Action | Details |
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| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

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| Sep 22, 2047 | 4.066 | 400 |
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| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – April 27, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
    - As of December 31, 2017, OPG had a cash position of $234 million.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **2017 Actual** | **Q1-Q4 2018 Forecast** | **2018 Forecast** |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at April 23, 2018, 2017):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected a $273 million in cash at the end of 2018.
    - As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 20187-202119 Business Plan, OPG is expected to spentd $1,249152 million in 2017 and projects to spend $1,231113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

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Commented [JK1]: Would it be OK to use the latest BP?

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income related to the January 1, 2017 to May 31, 2017 period.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033, , $382 million of subordinated debt and $98 million of junior subordinated debt.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038, $XX million of subordinated debt and $XX million of junior subordinated debt.

**Commented [GH2]:** Do we have confirmation from OPG how the remaining debt was financed from last Wednesday?

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- So far, the Trust has purchased approximately $1.8 billion financing receivable assets from the IESO, and issued $XX billion of notes payable.

Commented [GH3]: Pending numbers from the above.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
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| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
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* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to

purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
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| Timing | Action | Details |
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
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| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
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| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
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| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected a $273 million in cash at the end of 2018.
    - o As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - o In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - o OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - o OPG has also received concurrence from the Ministry of Energy for its 20172018-2019 2021 Business Plan. The Business Plan projects a borrowing need ofstated that as of December 31, 2017 they borrowed $1,301750 million of general corporate debt, of which $800 million was from in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from ththe credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In Tthe 20187-20211 9 Business Plan also stated that, OPG is expected to spentd $1,249152 million in 2017 and projects to spend $1,231113 million in 2018 on the Darlington Refurbishment project.

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- In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income related to the January 1, 2017 to May 31, 2017 period.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033, , $382 million of subordinated debt and $98 million of junior subordinated debt.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- On April 19, 2018, the Trust issued $400 million of senior notes payable maturing in 2038, $XX million of subordinated debt and $XX million of junior subordinated debt.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million.

- So far, the Trust has purchased approximately $1.8 billion financing receivable assets from the IESO, and issued $XX billion of notes payable.

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- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and

in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
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**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

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**OEFC Board Meeting – April 27, 2018**

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    - ~~o~~ On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- On April 19, 2018, the Trust issued $400 million of senior notes payable. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined. ~~maturing in 2038, $XX million of subordinated debt and $XX million of junior subordinated debt~~.

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| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected a $273 million in cash at the end of 2018.
    - As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2018-2021 Business Plan. The Business Plan stated that as of December 31, 2017 they borrowed $1,301 million of general corporate debt, of which $800 million was from the credit facility. The 2018-2021 Business Plan also stated that, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, they borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017, and their decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

    - In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

    - In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is still currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income related to the January 1, 2017 to May 31, 2017 period.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding with $500 million of senior notes payable, $382 million of subordinated debt and $98 million of junior subordinated debt. This left $199 million in OPG's warehouse funding facility.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million. On April 19, 2018, the Trust issued $400 million of senior notes payable. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | (484) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | (19) | - |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519M. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at April 23, 2018, 2017):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**April 23, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over 475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

**Commented [EJ1]:** Pg 53 of pdf of opg q4

**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017. OPG has presented their arguments in a hearing in April 2017 and this case is currently ongoing.

- The OEB decisions to come in the future related to the items mentioned above, with respect to OPG's rate application including, the effective date for new rates, the revenue requirement request, and proposed rate smoothing, would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
(Note – numbers are subject to rounding)

**(REFER TO PG. 41 of OPG Business Plan for this chart…did a yearly projection update since we don't have monthly information anymore)**

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |

**Commented [EJ3]:** OPG Q4 2017 pg. 2 of pdf

**Commented [EJ4]:** OPG Q4 2017 pg. 2 of pdf

Thought we should mention the Fair hydro plan info in the note since the chart below will have values related to the FHTrust. But unsure how much detail we need to give

| | | | |
|---|---|---|---|
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Proceeds of Distribution to Trillium Trust*** | - | - | - |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The PILs associated with the head office properties sale is assumed to be included in the "Cash from Operations", and the net book value is assumed to be $104 million.

Note that the Trillium Trust regulation timing is likely to be in 2018. As per OPG's Q3 2017 financial statements, OPG expected the transfer of net proceeds to take place as early as in the fourth quarter of 2017; the transfer is now likely to be in 2018 ~~as [insert rationale – per SIFB]~~in order to finalize analysis and verify records in support of prescribed costs under the *Trillium Trust Act, 2014*.

**Commented [EJ5]:** We always seem to have taken the "General Corporate Debt" number from the monthly OPG pdf's but don't know if taking the whole number and categorizing it as New Debt to OEFC is accurate.

Referring to pg. 130 of OPG q4 2017 debt to OEFC adds up to 800M and OPG also issued Medium Term Note (not to OEFC) of 500M. So maybe this line should actually have 800M and we should have another line as "Additional Corporate Debt" and put 501M in it?

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**Commented [EJ7]:** New row added

**Commented [EJ8]:** Does not seem to be included in the cashflow statement?

**Commented [EJ9]:** New row added

**Commented [EJ10]:** Pg. 156 of OPG Q4 2017

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2017 | 5.47 | 50 |
| Jan 22, 2018 | 5.218 | 75 |
| Mar 22, 2018 | 5.09 | 200 |
| Apr 22, 2018 | 5.424 | 50 |
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – April 27, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of December 31, 2017, OPG had a cash position of $234 million. In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - OPG had a $186 million cash position at the end of 2016.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. The Business Plan projects a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This change, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount. In the 2017-2019 Business Plan, OPG is expected to spend $1,152 million in 2017 and $1,113 million in 2018 on the Darlington Refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
- As of December 31, 2017 OPG has borrowed a total of $800 million under the credit facility. The term of all of the borrowings is 30 years.
- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued their decision in December 2017 and their decision determined that new prices would be applied with an effective date of June 1, 2017.

**Commented [EJ1]:** Pg 53 of pdf of opg q4

**Commented [EJ2]:** Looks like in 2018 they are expecting to pay 482M in dividends based on the cashflow statements.

They also mention in the business plan on page 18:

"In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder in respect of these transactions."

- OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period.

- In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.

- In January 2018, OPG has filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017. OPG has presented their arguments in a hearing in April 2017 and this case is currently ongoing.

- The OEB decisions to come in the future related to the items mentioned above, with respect to OPG's rate application including, the effective date for new rates, the revenue requirement request, and proposed rate smoothing, would affect OPG's longer term liquidity outlook.

- OPG has been appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

- **OPG Current Financial Outlook, based upon financing updates up to December 31, 2017:**
  (Note – numbers are subject to rounding)

  **(REFER TO PG. 41 of OPG Business Plan for this chart…did a yearly projection update since we don't have monthly information anymore)**

| *Calendar Years,($ millions)* | 2017 Actual | Q1-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186** | **48** | **234** |
| Cash from Operations | 944 | 524 | 1,468 |
| Approved Capital Expenditures | (1,853) | (213) | (2,066) |
| PS Term Deposit Maturity | 70 | - | - |
| Pre-tax Proceeds – Sale of Head Office | 484 | - | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |

**Commented [EJ3]:** OPG Q4 2017 pg. 2 of pdf

**Commented [EJ4]:** OPG Q4 2017 pg. 2 of pdf

Thought we should mention the Fair hydro plan info in the note since the chart below will have values related to the FHTrust. But unsure how much detail we need to give

**Commented [SK5R4]:** I think we've had a second tranche.

| | | | |
|---|---|---|---|
| Acquisition of Fair Hydro Trust financing receivables | (1,179) | (1,147) | (2,326) |
| Maturing Debt | (1,103) | 705 | (398) |
| New Debt to OEFC* | 1,301 | (110) | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601 | 583 | 1,184 |
| Issuance of Class A Shares** | 519 | 503 | 1,022 |
| Commercial Paper | 260 | (60) | 200 |
| Proceeds of Distribution to Trillium Trust*** | - | - | - |
| Distributions to Non-Controlling Interest | (15) | (7) | (22) |
| Capital Contribution from Non-Controlling Interest | 19 | - | - |
| Dividends | - | (482) | (482) |
| **Net Cash flow** | **48** | **(9)** | **39** |
| **Ending Cash** | **234** | **39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan.

** In December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

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**Commented [EJ11]:** Pg. 156 of OPG Q4 2017

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| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at December 5, 2017):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
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| Apr 22, 2023 | 2.961 | 20 |
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| Feb 22, 2047 | 4.122 | 200 |
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| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| **Total Outstanding** | | **3,245.0** |

**Status of Project Financing (at December 5, 2017):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $800 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Capital Markets Division and Electricity Finance Branch**
**April 20, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June XX~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
  - As of ~~December~~March 31, 2017, OPG had a cash position of $~~234~~ 328 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $~~186~~ 234 million cash position at the end of ~~2016~~2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. ~~The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.~~On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- IOn April 19, 2018, the Trust issued a total of $784 million in term debt funding consisting of the Trust issued $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038. This left $23 million in OPG's warehouse funding facility. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December March 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 20187 Actual | Q12-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186234** | **48328** | **234** |
| Cash from Operations | 944226 | 5241,242 | 1,468 |
| Approved Capital Expenditures | (1,853417) | (2131,649) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484273 | (484273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179460) | (1,147866) | (2,326) |
| Maturing Debt | (1,103275) | (123)705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301600 | (110)591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601732 | 452583 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | 519202 | 503820 | 1,022 |
| Commercial Paper | 260 | (60)200 | 200 |
| Distributions to Non-Controlling Interest | (154) | ((7)18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482199) | (482) |
| **Net Cash flow** | **4894** | **(956)** | **39** |
| **Ending Cash** | **234328** | **27239** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and

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~~in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.~~.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
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| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018~~, 2017~~):**

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| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

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**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June 22~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
  - As of ~~December~~March 31, 2017, OPG had a cash position of $~~234~~ 328 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $~~186~~ 234 million cash position at the end of ~~2016~~2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG hasDuring the first quarter of 2018, it borrowed an additional $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

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    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

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**Commented [BA1]:** wondering about the "long-term" language. an amended decision would result in a one-time increase to net income and cash?

**Commented [EJ2]:** I think at that time it may have seemed "longer term" in the sense that this was couple months ago….but we can change that to "future" instead

**Commented [BA3]:** fair to say?

**Commented [EJ4R3]:** Yes thank you

subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

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| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7~~April 23~~, 2018~~, 2017~~):**

Commented [EJ17]: Must request update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7~~April 23~~, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ18]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June 22~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
  - As of ~~December~~March 31, ~~2017~~2018, OPG had a cash position of $~~234~~ 328 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $~~186~~ 234 million cash position at the end of ~~2016~~2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- o ~~In~~ Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has~~During the first quarter of 2018, it~~ borrowed ~~an additional~~ $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and ~~its decision~~ determined ~~that~~ new ~~prices~~ rates would be applied with an effective date of June 1, 2017.

  - o OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

  - o In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. ~~The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.~~On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

  - o In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April ~~2017~~2018. This case is currently being reviewed by the OEB.

  - o A favourable~~n amended~~ OEB decision with respect to the Motion to Review w~~e~~ould have a positive impact on ~~affect~~ OPG's ~~longer term~~future liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - o As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in

**Commented [BA1]:** wondering about the "long-term" language. an amended decision would result in a one-time increase to net income and cash?

**Commented [EJ2]:** I think at that time it may have seemed "longer term" in the sense that this was couple months ago….but we can change that to "future" instead

**Commented [BA3]:** fair to say?

**Commented [EJ4R3]:** Yes thank you

subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.
- IOn April 19, 2018, the Trust issued a total of $784 million in term debt funding consisting of the Trust issued $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038. This left $23 million in OPG's warehouse funding facility. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.
- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to ~~December~~ March 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 2018~~7~~ Actual | Q~~1~~2-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **~~186~~234** | **~~48~~328** | **234** |
| Cash from Operations | ~~944~~226 | ~~524~~1,242 | 1,468 |
| Approved Capital Expenditures | (~~1,853~~417) | (~~213~~1,649) | (2,066) |
| PS Term Deposit Maturity | ~~70~~ - | ~~(70)~~ - | - |
| Pre-tax Proceeds – Sale of Head Office | ~~484~~273 | (~~484~~273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~1,179~~460) | (1,~~147~~866) | (2,326) |
| Maturing Debt | (~~1,103~~275) | ~~(123)705~~ | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~1,301~~600 | ~~(110)~~591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~601~~732 | ~~452~~583 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | ~~519~~202 | ~~503~~820 | 1,022 |
| Commercial Paper | ~~260~~ - | ~~(60)~~200 | 200 |
| Distributions to Non-Controlling Interest | (~~154~~) | ~~(7)~~18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | ~~-~~(283) | (~~482~~199) | (482) |
| **Net Cash flow** | **~~48~~94** | **(~~956~~)** | **39** |
| **Ending Cash** | **~~234~~328** | **~~272~~39** | **273** |

**Commented [SK5]:** What's the source of this?

**Commented [EJ6]:** Number are from cash flow statement pg. 47 of Q1

**Commented [EJ7]:** Numbers are from cash flow projection statement in 2018-2021 Business plan

**Commented [EJ8]:** 226

**Commented [EJ9]:** 0 or -

**Commented [EJ10]:** 273

**Commented [EJ11]:** 600

**Commented [EJ12]:** 732

**Commented [EJ13]:** 202

**Commented [EJ14]:** 1295 + (1295) = 0

**Commented [EJ15]:** (283)

**Commented [EJ16]:** 94

**Commented [EJ17]:** 328

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M ~~and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.~~.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
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Commented [EJ18]: Must request update from CMD

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| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ19]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June 22~~27~~, 2018**

## Purpose

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  - o In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. ~~The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.~~On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

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  - o A favourable~~n amended~~ OEB decision with respect to the Motion to Review w~~e~~ould have a positive impact on ~~affect~~ OPG's ~~longer term~~future liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

  - o As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in

**Commented [BA1]:** wondering about the "long-term" language. an amended decision would result in a one-time increase to net income and cash?

**Commented [EJ2]:** I think at that time it may have seemed "longer term" in the sense that this was couple months ago….but we can change that to "future" instead

**Commented [BA3]:** fair to say?

**Commented [EJ4R3]:** Yes thank you

subordinated debt and $98 million in junior subordinated debt maturing in 2033. ~~This left $199 million in OPG's warehouse funding facility.~~

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.
- ~~I~~On April ~~19,~~ 2018, the Trust issued a total of $784 million in term debt funding consisting of ~~the Trust issued~~ $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038. ~~The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.~~
- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to ~~December~~ March 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 2018~~7~~ Actual | Q~~1~~2-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **~~186~~234** | **~~48~~328** | **234** |
| Cash from Operations | ~~944~~226 | ~~524~~1,242 | 1,468 |
| Approved Capital Expenditures | (~~1,853~~417) | (~~213~~1,649) | (2,066) |
| PS Term Deposit Maturity | ~~70~~ - | ~~(70)~~ - | - |
| Pre-tax Proceeds – Sale of Head Office | ~~484~~273 | (~~484~~273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~1,179~~460) | (1,~~147~~866) | (2,326) |
| Maturing Debt | (~~1,103~~275) | ~~(123)705~~ | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~1,301~~600 | ~~(110)~~591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~601~~732 | ~~452~~583 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | ~~519~~202 | ~~503~~820 | 1,022 |
| Commercial Paper | ~~260~~ - | ~~(60)~~200 | 200 |
| Distributions to Non-Controlling Interest | (~~154~~) | ~~(7)~~18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | ~~-~~(283) | (~~482~~199) | (482) |
| **Net Cash flow** | **~~48~~94** | **(~~956~~)** | **39** |
| **Ending Cash** | **~~234~~328** | **~~272~~39** | **273** |

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Debt Funding – Tracking Sheet_v3.xlsx
Tab: 2018-04-24

Mention of remaining balance can be removed as it is internal calculation.

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* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M ~~and in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.~~.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

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**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
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| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7~~April 23~~, 2018~~, 2017~~):**

Commented [EJ19]: Must request update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7~~April 23~~, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ20]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June XX~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
  - As of ~~December~~March 31, 2017, OPG had a cash position of $~~234~~ 328 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $~~186~~ 234 million cash position at the end of ~~2016~~2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. ~~The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.~~On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's longer term liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

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- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- IOn April 19, 2018, the Trust issued a total of $784 million in term debt funding consisting of the Trust issued $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038. This left $23 million in OPG's warehouse funding facility. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December March 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 20187 Actual | Q12-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186234** | **48328** | **234** |
| Cash from Operations | 944226 | 5241,242 | 1,468 |
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| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484273 | (484273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179460) | (1,147866) | (2,326) |
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| New Debt to OEFC and Additional Corporate Debt* | 1,301600 | (110)591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601732 | 452583 | 1,184 |
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| Distributions to Non-Controlling Interest | (154) | ((7)18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482199) | (482) |
| **Net Cash flow** | **4894** | **(956)** | **39** |
| **Ending Cash** | **234328** | **27239** | **273** |

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| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018~~, 2017~~):**

Commented [EJ14]: Must request update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ15]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June XX~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
  - As of ~~December~~March 31, 2017, OPG had a cash position of $~~234~~ 328 million.
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - OPG had a $~~186~~ 234 million cash position at the end of ~~2016~~2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
  - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.

- In the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. ~~The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017.~~On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2017. This case is currently being reviewed by the OEB.

    - An amended OEB decision with respect to the Motion to Review could affect OPG's ~~longer term~~future liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033. This left $199 million in OPG's warehouse funding facility.

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- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

- IOn April 19, 2018, the Trust issued a total of $784 million in term debt funding consisting of the Trust issued $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038. This left $23 million in OPG's warehouse funding facility. The amounts of subordinated and junior subordinated debts along with the amounts left in the warehouse funding facility are still to be determined.

- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to December March 31, 2017:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 20187 Actual | Q12-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **186234** | **48328** | **234** |
| Cash from Operations | 944226 | 5241,242 | 1,468 |
| Approved Capital Expenditures | (1,853417) | (2131,649) | (2,066) |
| PS Term Deposit Maturity | 70 | (70) | - |
| Pre-tax Proceeds – Sale of Head Office | 484273 | (484273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (1,179460) | (1,147866) | (2,326) |
| Maturing Debt | (1,103275) | (123)705 | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,301600 | (110)591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 601732 | 452583 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | 519202 | 503820 | 1,022 |
| Commercial Paper | 260 | (60)200 | 200 |
| Distributions to Non-Controlling Interest | (154) | ((7)18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482199) | (482) |
| **Net Cash flow** | **4894** | **(956)** | **39** |
| **Ending Cash** | **234328** | **27239** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M and

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**Commented [EJ3]:** Number are from cash flow statement pg. 47 of Q1

**Commented [EJ4]:** Numbers are from cash flow projection statement in 2018-2021 Business plan

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**Commented [EJ12]:** (283)

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~~in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.~~.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
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| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
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| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
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**OPG Debt Maturity Schedule (at April 23, 2018~~, 2017~~):**

Commented [EJ15]: Must request update from CMD

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|---|---|---|
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**Status of Project Financing (at April 23, 2018):**

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| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ16]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – ~~April~~ June 22~~27~~, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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- In 2017, OPG borrowed a total of $800 million under the credit facility. During the first quarter of 2018, it borrowed an additional $600 million. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and its decision determined that new prices would be applied with an effective date of June 1, 2017.

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**Commented [EJ4R3]:** Yes thank you

- On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

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- On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to ~~December~~ March 31, 2017:** (Note – numbers are subject to rounding)

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| Approved Capital Expenditures | (~~1,853~~417) | (~~213~~1,649) | (2,066) |
| PS Term Deposit Maturity | ~~70~~ - | ~~(70)~~ - | - |
| Pre-tax Proceeds – Sale of Head Office | ~~484~~273 | (~~484~~273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~1,179~~460) | (1,~~147~~866) | (2,326) |
| Maturing Debt | (~~1,103~~275) | (123)~~705~~ | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~1,301~~600 | (110)591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~601~~732 | ~~452~~583 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | ~~519~~202 | ~~503~~820 | 1,022 |
| Commercial Paper | ~~260~~ - | (60)200 | 200 |
| Distributions to Non-Controlling Interest | (~~15~~4) | (~~(7)~~18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | ~~(~~(283) | (~~482~~199) | (482) |
| **Net Cash flow** | **~~48~~94** | **(~~956~~)** | **39** |
| **Ending Cash** | **~~234~~328** | **~~272~~39** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M ~~and~~

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**Commented [EJ6]:** Numbers are from cash flow projection statement in 2018-2021 Business plan

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~~in Oct 2017 OPG issued $500M of senior notes payable under a Medium Term Note Program for general corporate purposes.~~.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at April 23, 2018~~, 2017~~):**

Commented [EJ17]: Must request update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at April 23, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Commented [EJ18]:** Must request update from CMD

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June XX~~April 23~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – June 22, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
    - As of March 31, 2018, OPG had a cash position of $328 million.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $234 million cash position at the end of 2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and determined new rates would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - In April 2018, the Trust issued a total of $784 million in term debt funding consisting of $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
(Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 2018 Actual | Q2-Q4 2018 Forecast | 2018 Forecast |
|---|---|---|---|
| **Opening Cash** | **234** | **328** | **234** |
| Cash from Operations | 226 | 1,242 | 1,468 |
| Approved Capital Expenditures | (417) | (1,649) | (2,066) |
| PS Term Deposit Maturity | - | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | (273) | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (460) | (1,866) | (2,326) |
| Maturing Debt | (275) | (123) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 600 | 591 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 732 | 452 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | 500 | - |
| Issuance of Class A Shares** | 202 | 820 | 1,022 |
| Commercial Paper | - | 200 | 200 |
| Distributions to Non-Controlling Interest | (4) | (18) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (199) | (482) |
| **Net Cash flow** | **94** | **(56)** | **39** |
| **Ending Cash** | **328** | **272** | **273** |

**Commented [EJ1]:** Number are from cash flow statement pg. 47 of Q1

**Commented [EJ2]:** Numbers are from cash flow projection statement in 2018-2021 Business plan

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
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| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7, 2018):**

Commented [EJ3]: Received update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 8, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – June 22, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
    - As of March 31, 2018, OPG had a cash position of $328 million.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $234 million cash position at the end of 2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and determined new rates would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - In April 2018, the Trust issued a total of $784 million in term debt funding consisting of $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
  (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 226 | 1,468 |
| Approved Capital Expenditures | (417) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (460) | (2,326) |
| Maturing Debt | (275) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 600 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 732 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | - |
| Issuance of Class A Shares** | 202 | 1,022 |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (4) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **94** | **39** |
| **Ending Cash** | **328** | **273** |

**Commented [EJ2]:** Numbers are from cash flow projection statement in 2018-2021 Business plan

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* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
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| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7, 2018):**

Commented [EJ3]: Received update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 8, 2018**

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    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- On June 20, 2018, IESO is expected to rollover $257 million under its facility with the OFA and requested a new advance for $310 million which will bring its balance to $567 million. A decision was made to not sell the assets to OPG Trust pending the new government expected to be sworn in on June 29, 2018.

- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
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| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7, 2018):**

Commented [EJ3]: Received update from CMD

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 8, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – June 22, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- As of February 2018, according to OPG's business plan, OPG projected $273 million in cash at the end of 2018.
    - As of March 31, 2018, OPG had a cash position of $328 million.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
    - OPG had a $234 million cash position at the end of 2017.
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016
    - OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and determined new rates would be applied with an effective date of June 1, 2017.

    - OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.

    - In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.

    - In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's decision of rates being effective June 1, 2017 instead of the requested date of January 1, 2017 and an oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act:

    - As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033.

    - On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.

    - In April 2018, the Trust issued a total of $784 million in term debt funding consisting of $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038.

    - On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.

- On June 20, 2018, IESO is expected to rollover $257 million under its facility with the OFA and requested a new advance for $310 million which will bring its balance to $567 million. A decision was made to not sell the assets to OPG Trust pending the new government expected to be sworn in on June 29, 2018.

- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
  (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **Q1 2018 Actual** | **2018 Forecast** |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 226 | 1,468 |
| Approved Capital Expenditures | (417) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (460) | (2,326) |
| Maturing Debt | (275) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 600 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 732 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | - |
| Issuance of Class A Shares** | 202 | 1,022 |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (4) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **94** | **39** |
| **Ending Cash** | **328** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at June 7, 2018):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
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| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
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| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 18, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – June 22, 2018**

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- ~~As of February 2018, according to~~ OPG's 2018 business plan~~, OPG~~ projected $273 million in cash at the end of 2018. OPG has provided no updates.
  - As of March 31, 2018, OPG had a cash position of $328 million. OPG had a $234 million cash position at the end of 2017.
  - ~~o~~
  - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
    - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
  - ~~o OPG had a $234 million cash position at the end of 2017.~~
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project. ~~The Minister's directive from June 2016 allowed OEFC to extend the term of the credit facility to the end of 2018, and increase the amount of the credit facility based on the total financing amount identified in OPG's 2016-2018 Business Plan, following concurrence by the Minister of Energy. OPG obtained concurrence for its Business Plan in November 2016~~
  - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
  - ~~o OPG has also received concurrence from the Ministry of Energy for its 2017-2019 Business Plan. That Business Plan projected a borrowing need of $1,750 million in 2017 ($1,500 million in 2016-18 Business Plan) and $650 million total in 2018 ($850 million in 2016-18 Business Plan) from the credit facility. This revised amount, in aggregate, is close to the approved amounts of the Minister's directive between 2017 and 2018, and the shift in the timing of about $200 million from 2018 to 2017 is consistent with the Directive on the total financing amount.~~

- ~~In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018.~~

- In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.

- Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.

- ~~In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.~~

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- ~~OPG filed its regulated rate application in May 2016 for rates starting as at January 1, 2017 and covering a period of 5 years from 2017 to 2021. The Ontario Energy Board (OEB) issued its decision in December 2017, and determined new rates would be applied with an effective date of June 1, 2017.~~

  - ~~OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in a net revenue increase of approximately $480 million related to the June 1, 2017 to December 31, 2017 period, compared to the prior rates.~~

  - ~~In January 2018, OPG also submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. On March 29, 2018, the OEB issued the final payment amounts order establishing new regulated prices of OPG's regulated facilities, with an effective date of March 1, 2018.~~

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- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC is not involved in any of the planned financings by OPG for the Trust.~~:~~

  - ~~As reported in OPG's Q4 2017 Financial Statement, in December 2017 the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.18 billion. In February 2018, the Trust issued a total of $980 million in term debt~~

~~funding consisting of $500 million in senior notes payable, $382 million in subordinated debt and $98 million in junior subordinated debt maturing in 2033.~~

- ~~On March 22, 2018, OPG purchased the second tranche of financing receivable assets from the IESO in the amount of approximately $460 million.~~

- ~~In April 2018, the Trust issued a total of $784 million in term debt funding consisting of $400 million of senior notes payable, $306 million in subordinated debt and $78 million in junior subordinated debt maturing in 2038.~~

- ~~On April 20, 2018, OPG purchased the third tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $149 million. Additional note offerings are anticipated.~~

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- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
  (Note – numbers are subject to rounding)

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| Issuance of Fair Hydro Trust long-term debt | 732 | 1,184 |
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| Issuance of Class A Shares** | 202 | 1,022 |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (4) | (22) |
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*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

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| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7, 2018):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 18, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – June 22, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- OPG's 2018 business plan projected $273 million in cash at the end of 2018. OPG has provided no updates.
    - As of March 31, 2018, OPG had a cash position of $328 million. OPG had a $234 million cash position at the end of 2017.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

- A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC is not involved in any of the planned financings by OPG for the Trust.

- **OPG Current Financial Outlook, based upon financing updates up to March 31, 2017:**
(Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **Q1 2018 Actual** | **2018 Forecast** |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 226 | 1,468 |
| Approved Capital Expenditures | (417) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (460) | (2,326) |
| Maturing Debt | (275) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 600 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | 732 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (500) | - |
| Issuance of Class A Shares** | 202 | 1,022 |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (4) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **94** | **39** |
| **Ending Cash** | **328** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018.

Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at June 7, 2018):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**June 18, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's 2018 business plan projected $273 million in cash at the end of 2018. OPG has provided no updates.
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017.

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An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

  - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC is not involved in any of the planned financings by OPG for the Trust.

- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

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| *Calendar Years,($ millions)* | Q~~1~~2 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | 1,468 |
| Approved Capital Expenditures | (~~417~~807) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (95~~00~~) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **~~351~~94** | **39** |
| **Ending Cash** | **~~328~~585** | **273** |

*~~–~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

**~~–~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of

44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018. ~~December 2017.~~ ~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.~~

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at June 7, 2018):**

Commented [AA1]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Jul 22, 2018 | 5.497 | 50 |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,470.0** |

**Status of Project Financing (at June 7, 2018):**

Commented [AA2]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's 2018 business plan projected $273 million in cash at the end of 2018. OPG has provided no updates.
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC is not involved in any of the planned financings by OPG for the Trust.

- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

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| *Calendar Years,($ millions)* | Q~~1~~2 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | 1,468 |
| Approved Capital Expenditures | (~~417~~807) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (95~~~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **~~35194~~351** | **39** |

| | | |
|---|---|---|
| **Ending Cash** | ~~328~~585 | **273** |

* ~~–~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** ~~–~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in ~~–~~April 2018. ~~December 2017.In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.~~

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
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| Apr 22, 2019 | 5.635 | 75 |
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| Oct 22, 2019 | 4.857 | 85 |
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| Jul 22, 2020 | 4.658 | 35 |
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| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
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| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
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| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
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| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's 2018 business plan projected $273 million in cash at the end of 2018. OPG has provided no updates.
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC was ~~is~~ not involved and at this time has no direction to be involved in any of the planned financing~~s~~ by OPG for the Trust.]
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q~~1~~2 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | 1,468 |
| Approved Capital Expenditures | (~~417~~807) | (2,066) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | 273 | - |
| Pre-tax Proceeds – Sale of Lakeview Site | - | 267 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,191 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | 1,184 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

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| | | |
|---|---|---|
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (482) |
| **Net Cash flow** | **351~~94~~** | **39** |
| **Ending Cash** | **~~328~~585** | **273** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018. ~~December 2017.~~ ~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.~~

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA3]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA4]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's July 2018 ~~business plan~~forecast ~~projected~~ projects $~~273~~ 414 million in cash at the end of 2018. ~~OPG has provided no updates.~~
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC was ~~is~~ not involved and at this time has no direction to be involved in any of the planned financing~~s~~ by OPG for the Trust.]
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q~~2~~1 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | ~~1,468~~1,623 |
| Approved Capital Expenditures | (~~417~~807) | (2,~~066~~081) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | ~~273~~- | - |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | ~~267~~273 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,19~~0~~1 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

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| | | |
|---|---|---|
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | ~~(482)~~(488) |
| **Net Cash flow** | **~~351~~94** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **~~273~~414** |

* ~~-~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** ~~-~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in ~~-~~April 2018. ~~December 2017.~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
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| Timing | Action | Details |
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| Timing | Action | Details |
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| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
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**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA3]: Update from CMD required.

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|---|---|---|
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| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA4]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
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| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

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- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q~~1~~2 2018 Actual | Forecast Q3-Q4 2018 | 2018 ~~Forecast~~ |
|---|---|---|---|
| **Opening Cash** | **234** | **585** | **234** |
| Cash from Operations | ~~226~~639 | 984 | ~~1,468~~1,623 |
| Approved Capital Expenditures | (~~417~~807) | (1,274) | (2,~~066~~081) |
| PS Term Deposit Maturity | - | | - |
| Pre-tax Proceeds – Sale of Head Office | ~~273~~- | | - |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | - | ~~267~~273 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (1,717) | (2,326) |
| Maturing Debt | (~~275~~327) | (71) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 152 | 1,19~~0~~1 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | (29) | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | 900 | - |
| Issuance of Class A Shares** | ~~202~~268 | 754 | 1,022 |
| Issuance of short-term debt | 2,549 | (2,549) | - |

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

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| | | | |
|---|---|---|---|
| Repayment of short-term debt | (2,695) | 2,695 | - |
| Commercial Paper | - | 200 | 200 |
| Distributions to Non-Controlling Interest | (~~4~~10) | (12) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (205) | ~~(482)~~(488) |
| **Net Cash flow** | **351~~94~~** | **(172)** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **414** | **~~273~~414** |

* ~~-~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** ~~-~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in ~~-~~April 2018. ~~December 2017.~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA3]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA4]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's July 2018 ~~business plan~~forecast ~~projected~~ projects $~~273~~ 414 million in cash at the end of 2018. ~~OPG has provided no updates.~~
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC was ~~is~~ not involved and at this time has no direction to be involved in any of the planned financing~~s~~ by OPG for the Trust.]
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q~~2~~1 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | ~~1,468~~1,623 |
| Approved Capital Expenditures | (~~417~~807) | (2,~~066~~081) |
| PS Term Deposit Maturity | - | - |
| Pre-tax Proceeds – Sale of Head Office | ~~273~~- | - |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | ~~267~~273 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,19~~0~~1 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

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| | | |
|---|---|---|
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | ~~(482)~~(488) |
| **Net Cash flow** | **~~351~~94** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **~~273~~414** |

* ~~-~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** ~~-~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in ~~-~~April 2018. ~~December 2017.~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
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| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
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| Timing | Action | Details |
|---|---|---|
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
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| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
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| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA3]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
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| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA4]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's July 2018 ~~business plan~~forecast ~~projected~~ projects $~~273~~ 414 million in cash at the end of 2018. ~~OPG has provided no updates.~~
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - In 2018, OPG expects to make dividend payments of over $475 million to the Shareholder with respect to the sale of OPG's head office and their Lakeview site.
        - In March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC was ~~is~~ not involved and at this time has no direction to be involved in any of the planned financing~~s~~ by OPG for the Trust.]
    - As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Th~~is~~e regulatory assets include~~s~~ the interest costs related to the GA deferral ~~as~~. OPG ~~would~~ provide~~s~~ the ~~carrying~~ costs to carry the deferral ~~information~~ to the IESO ~~to be~~ which is included as part of the regulatory assets sold to the Trust.
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q~~2~~1 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | ~~1,468~~1,623 |
| Approved Capital Expenditures | (~~417~~807) | (2,~~066~~0381) |
| ~~PS Term Deposit Maturity~~ | ~~-~~ | ~~-~~ |
| ~~Pre-tax Proceeds – Sale of Head Office~~ | ~~273~~- | ~~-~~ |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | ~~267~~273 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,19~~0~~1 |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |

**Commented [GH1]:** I think it was fine the way it was before since as of today, OEFC is still not involved.

**Commented [SK2]:** Happy to omit or modify. Just want to indicate no involvement thus far.

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| | | |
|---|---|---|
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | ~~(482)~~(488) |
| **Net Cash flow** | **~~351~~94** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **~~273~~414** |

* ~~-~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017 debt to OEFC totaled to $800M.

** ~~-~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in ~~-~~April 2018. ~~December 2017.~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is likely to be in 2018. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA3]: Update from CMD.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA4]: Update from CMD.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's July 2018 ~~business plan~~forecast ~~projected~~ projects $~~273~~ 414 million in cash at the end of 2018. ~~OPG has provided no updates.~~
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - Later i~~i~~n 2018, OPG expects to make dividend payments of ~~over~~about $~~475~~200 million to the Shareholder with respect to the sale of OPG's ~~head office and their~~ Lakeview site.
        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - ~~In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.~~
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

In addition to borrowing from OEFC, OPG also borrows in the capital markets. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program, maturing in 2048.

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- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC haswas is not been involved in any of the planned financings by OPG for the Trust.]

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    - ~~As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Thise regulatory assets includes the interest costs related to the GA deferral as. OPG would provides the carrying costs to carry the deferral information to the IESO to be which is included as part of the regulatory assets sold to the Trust.~~
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

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| *Calendar Years,($ millions)* | Q2~~1~~ 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | ~~226~~639 | ~~1,468~~1,623 |
| Approved Capital Expenditures | (~~417~~807) | (2,~~066~~0381) |
| ~~PS Term Deposit Maturity~~ | ~~-~~ | ~~-~~ |
| ~~Pre-tax Proceeds – Sale of Head Office~~ | ~~273-~~ | ~~-~~ |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | ~~267~~273 |
| Acquisition of Fair Hydro Trust financing receivables | (~~460~~609) | (2,326) |
| Maturing Debt | (~~275~~327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,19~~0~~1 |

| | | |
|---|---|---|
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (95~~~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | ~~(482)~~(488) |
| **Net Cash flow** | **~~3~~351~~94~~** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **~~273~~414** |

* ~~Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017, debt to OEFC totalled to $800M.~~

** ~~In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018. ~~December 2017.~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.~~

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is TBD~~likely to be in 2018~~. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Commented [RK3]:** In Q2?

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
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| Timing | Action | Details |
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
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| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA4]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA5]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

**OPG Funding and Liquidity Status Update**
**OEFC Board Meeting – September 28, 2018 ~~June 22, 2018~~**

**Purpose**

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

**Current Status**

- OPG's July 2018 ~~business plan~~forecast ~~projected~~ projects $~~273~~ 414 million in cash at the end of 2018. ~~OPG has provided no updates.~~
    - As of June 30, 2018 ~~March 31, 2018,~~ OPG had a cash position of $~~328~~ 585 million. OPG had a $~~234~~ 328 million cash position at the end of ~~2017~~Q1 on March 31, 2018.
    - Later i~~i~~n 2018, OPG expects to make dividend payments of ~~over~~about $~~475~~200 million to the Shareholder with respect to the sale of OPG's ~~head office and their~~ Lakeview site.
        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - ~~In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048.~~
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based

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on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.

In addition to borrowing from OEFC, OPG also borrows in the capital markets. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program, maturing in 2048.

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- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.
    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.
- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. OEFC haswas is not been involved in any of the planned financings by OPG for the Trust.

Commented [GH1]: I think it was fine the way it was before since as of today, OEFC is still not involved.

Commented [SK2]: Happy to omit or modify. Just want to indicate no involvement thus far.

    - ~~As of today, OPG has completed three regulatory asset purchases from the IESO, and the Province has correspondingly completed three equity injections related to OPG's asset purchases. Thise regulatory assets includes the interest costs related to the GA deferral as. OPG would provides the carrying costs to carry the deferral information to the IESO to be which is included as part of the regulatory assets sold to the Trust.~~
- **OPG Current Financial Outlook, based upon financing updates up to ~~March 31, 2017~~ June 30, 2018:** (Note – numbers are subject to rounding)

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| *Calendar Years,($ millions)* | As at end of Q21 2018 Actual | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 226639 | 1,4681,623 |
| Approved Capital Expenditures | (417807) | (2,0660381) |
| ~~PS Term Deposit Maturity~~ | - | - |
| ~~Pre-tax Proceeds – Sale of Head Office~~ | ~~273~~- | - |
| Pre-tax Proceeds – Sale of Lakeview Site | 273- | 267273 |
| Acquisition of Fair Hydro Trust financing receivables | (460609) | (2,326) |
| Maturing Debt | (275327) | (398) |

| | | |
|---|---|---|
| New Debt to OEFC and Additional Corporate Debt* | ~~600~~1,047 | 1,19~~91~~ |
| Issuance of Fair Hydro Trust long-term debt | ~~732~~1,206 | ~~1,184~~1,177 |
| Repayment of Fair Hydro Trust long-term debt | (~~95~~00) | - |
| Issuance of Class A Shares** | ~~202~~268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (410) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | ~~(482)~~(488) |
| **Net Cash flow** | **~~351~~94** | **~~39~~179** |
| **Ending Cash** | **~~328~~585** | **~~273~~414** |

* Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017, debt to OEFC totalled to $800M.

** In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018. ~~December 2017.~~ ~~In March 2018 and December 2017, OPG issued non-voting Class A shares to the Province for its equity injection in the company, generating proceeds of $202M and $519M respectively. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.~~

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M shortly after as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is TBD~~likely to be in 2018~~. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

**Commented [RK3]:** In Q2?

**Background**

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016. An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

**OPG Debt Maturity Schedule (at September 17~~June 7~~, 2018):**

Commented [AA4]: Update from CMD required.

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| ~~Jul 22, 2018~~ | ~~5.497~~ | ~~50~~ |
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,4~~2~~7~~0~~0.0** |

**Status of Project Financing (at September~~June~~ 17, 2018):**

Commented [AA5]: Update from CMD required.

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17~~June 18~~, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – September 28, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- OPG's July 2018 forecast projects $414 million in cash at the end of 2018.
    - As of June 30, 2018 OPG had a cash position of $585 million. OPG had a $328 million cash position at the end of Q1 on March 31, 2018.
    - Later in 2018, OPG expects to make dividend payments of about $200 million to the Shareholder with respect to the sale of OPG's Lakeview site.
        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.
- In addition to borrowing from OEFC, OPG also borrows in the capital markets. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program, maturing in 2048.

- In January 2018, OPG also filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC has not been involved in any of the financings by OPG for the Trust.]

- **OPG Current Financial Outlook, based upon financing updates up to June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1-Q2 2018 Actuals | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 639 | 1,623 |
| Approved Capital Expenditures | (807) | (2,038) |
| Pre-tax Proceeds – Sale of Lakeview Site | 273 | 273 |
| Acquisition of Fair Hydro Trust financing receivables | (609) | (2,326) |
| Maturing Debt | (327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,047 | 1,199 |
| Issuance of Fair Hydro Trust long-term debt | 1,206 | 1,177 |
| Repayment of Fair Hydro Trust long-term debt | (900) | - |
| Issuance of Class A Shares** | 268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (10) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (488) |
| **Net Cash flow** | **351** | **179** |
| **Ending Cash** | **585** | **414** |

*Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017, debt to OEFC totalled to $800M.

**In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds

were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M in Q1 as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is TBD. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at September 17, 2018):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,420.0** |

**Status of Project Financing (at September 17, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – September 28, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- OPG's July 2018 forecast projects $414 million in cash at the end of 2018.
    - As of June 30, 2018 OPG had a cash position of $585 million. OPG had a $328 million cash position at the end of Q1 on March 31, 2018.
    - Later in 2018, OPG expects to make dividend payments of about $200 million to the Shareholder with respect to the sale of OPG's Lakeview site.
        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.
- In addition to borrowing from OEFC, OPG also borrows in the capital markets. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program, maturing in 2048.

- In January 2018, OPG ~~also~~ filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC has not been involved in any of the financings by OPG for the Trust.]

- **OPG Current Financial Outlook, based upon financing updates up to June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | Q1-Q2 2018 Actuals | 2018 Forecast |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 639 | 1,623 |
| Approved Capital Expenditures | (807) | (2,038) |
| Pre-tax Proceeds – Sale of Lakeview Site | 273 | 273 |
| Acquisition of Fair Hydro Trust financing receivables | (609) | (2,326) |
| Maturing Debt | (327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,047 | 1,199 |
| Issuance of Fair Hydro Trust long-term debt | 1,206 | 1,177 |
| Repayment of Fair Hydro Trust long-term debt | (900) | - |
| Issuance of Class A Shares** | 268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (10) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (488) |
| **Net Cash flow** | **351** | **179** |
| **Ending Cash** | **585** | **414** |

*Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017, debt to OEFC totalled to $800M.

**In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds

were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M in Q1 as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is TBD. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at September 17, 2018):

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**Status of Project Financing (at September 17, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
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| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17, 2018**

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# OEFC Board Meeting – September 28, 2018

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        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
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    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.
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| Cash from Operations | 639 | 1,623 |
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| Issuance of Class A Shares** | 268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
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| Distributions to Non-Controlling Interest | (10) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (488) |
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## Background

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| Timing | Action | Details |
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| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
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| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
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| Timing | Action | Details |
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| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
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| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at September 17, 2018):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,420.0** |

**Status of Project Financing (at September 17, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17, 2018**

# OPG Funding and Liquidity Status Update
# OEFC Board Meeting – September 28, 2018

## Purpose

The purpose of this report is to outline the status of OPG's funding and liquidity position on an on-going basis, as directed at the December 2004 OEFC Board meeting.

## Current Status

- OPG's July 2018 forecast projects $414 million in cash at the end of 2018.
    - As of June 30, 2018 OPG had a cash position of $585 million. OPG had a $328 million cash position at the end of Q1 on March 31, 2018.
    - Later in 2018, OPG expects to make dividend payments of about $200 million to the Shareholder with respect to the sale of OPG's Lakeview site.
        - In addition, in March 2018, OPG paid $283M in net proceeds from the head office properties sale to the Province as prescribed in regulation under the *Trillium Trust Act, 2014.*
- In June 2016, OEFC entered into a credit facility agreement with OPG for the latter to borrow up to $700 million for the purpose of financing general corporate purposes effective January 1, 2017 to the end of 2017, including for the Darlington refurbishment project.
    - In September 2017, amendments to the credit facility were finalized to increase the facility to $2.35 billion and extend the expiry date to December 31, 2018, based on OPG's 2016-18 Business Plan.
    - In 2017, OPG borrowed a total of $800 million under the credit facility. Year to date for 2018, OPG has borrowed $600 million, $200 million in January and $400 million in March. The term of all of the borrowings is 30 years.
    - Based on the 2018-2021 Business Plan, OPG spent $1,249 million in 2017 and projects to spend $1,231 million in 2018 on the Darlington Refurbishment project.
    - OPG has requested a credit facility from OEFC for up to $693 million for the period from January 1, 2019 to December 31, 2021. The $693 million is based on the 3 year borrowing requirements set out in OPG's 2018-2021 Business Plan. Staff are reviewing the request.
- In addition to borrowing from OEFC, OPG also borrows in the capital markets. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program, maturing in 2048.

- In January 2018, OPG filed a Notice of Motion to review and vary the OEB's December 2017 decision for OPG's rate application. The OEB decision was for new rates to be effective June 1, 2017 instead of the requested date of January 1, 2017. An oral hearing to present their arguments occurred on April 2018. This case is currently being reviewed by the OEB.

    - A favourable OEB decision with respect to the Motion to Review would have a positive impact on OPG's liquidity outlook and net income.

- OPG was appointed the Financial Services Manager under the Ontario Fair Hydro Plan Act, 2017 (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity for the Act. [OEFC has not been involved in any of the financings by OPG for the Trust.]

- **OPG Current Financial Outlook, based upon financing updates up to June 30, 2018:** (Note – numbers are subject to rounding)

| *Calendar Years,($ millions)* | **Q1-Q2 2018 Actuals** | **2018 Forecast** |
|---|---|---|
| **Opening Cash** | **234** | **234** |
| Cash from Operations | 639 | 1,623 |
| Approved Capital Expenditures | (807) | (2,038) |
| Pre-tax Proceeds – Sale of Lakeview Site | 273 | 273 |
| Acquisition of Fair Hydro Trust financing receivables | (609) | (2,326) |
| Maturing Debt | (327) | (398) |
| New Debt to OEFC and Additional Corporate Debt* | 1,047 | 1,199 |
| Issuance of Fair Hydro Trust long-term debt | 1,206 | 1,177 |
| Repayment of Fair Hydro Trust long-term debt | (900) | - |
| Issuance of Class A Shares** | 268 | 1,022 |
| Issuance of short-term debt | 2,549 | - |
| Repayment of short-term debt | (2,695) | - |
| Commercial Paper | - | 200 |
| Distributions to Non-Controlling Interest | (10) | (22) |
| Dividends (Net Proceeds of Distribution to Trillium Trust***) | (283) | (488) |
| **Net Cash flow** | **351** | **179** |
| **Ending Cash** | **585** | **414** |

*Financing from OEFC for general corporate purposes including Darlington Refurbishment project. The current credit facility allows up to $2.35 billion to the end of 2018 consistent with 2016-2018 OPG Business Plan. As of December 31, 2017, debt to OEFC totalled to $800M.

**In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. These proceeds

were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44%of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in April 2018.

*** The Trillium Trust regulation for the head office properties was filed in March 2018, with OPG paying the net proceeds of approximately $283M in Q1 as a dividend to the Province. Note that the Trillium Trust regulation timing for the Lakeview site is TBD. Analysis and verification of records in support of prescribed costs under the *Trillium Trust Act, 2014* needs to be undertaken.

## Background

The following table provides the details of deferrals of debt and interest payments, refinancing, and new loans commencing from December of 2004.

| Timing | Action | Details |
|---|---|---|
| July 2016 Board meeting | Received Minister's Directive on June 17, 2016, for general corporate purposes including Darlington Refurbishment project up to $700 million. Directive provides approval for subsequent loans not totalling more than $2.3 billion but is subject to concurrence by Shareholder with OPG's business plan, and to not exceed $3 billion in total. | Under credit facility, loans shall have a term not exceeding thirty years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread based on a survey of market rates. Interest rate and term of each loan shall be determined by OEFC.<br><br>Loan agreement signed on June 17, 2016.<br>An amendment was signed on September 6, 2017 to increase the amount of the credit facility to $1.5 billion in 2017 and $850 million in 2018. |
| December 2014 Board meeting | Subject to receiving Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $800 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Received Minister's directive on December 18, 2014. Loan agreement was signed on December 22, 2014. |
| December 2013 Board meeting | Received Minister's Directive for general corporate purposes including Darlington Refurbishment project up to $500 million. | Under the credit facility, up to 50% of advances may have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on December 20, 2013. |
| April 2012 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $400 million. | Under the credit facility, advances up to $200 million may have a term up to 30 years. The remaining $200 million may have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on April 26, 2012. |
| April 2011 Board meeting | Received Minister's Directive for refinancing of maturing debt up to $375 million. | Under the credit facility, each advance will have a term up to 30 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC. Loan agreement was signed on March 7, 2011. |
| September 2010 Board meeting | Received Minister's Directive for $700 million loan to OPG for the Lower Mattagami project. | Under the credit facility each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br>Loan agreement was signed on March 7, 2011. |

| Timing | Action | Details |
|---|---|---|
| September 2009 Board meeting | Subject to receiving Minister's directives, approved the refinancing of maturing debt up to $970 million and an increase in the Niagara Tunnel loan to $1.6 billion. | The refinancing debt facility will have a term of one year; each advance will have a term up to 10 years. The interest rate will be based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Received Minister's directive on January 20, 2010 for refinancing up to $970 million of maturing debt. Loan agreement signed March 8, 2010.<br><br>Received Minister's directive on April 22, 2010 for increase in the Niagara Tunnel loan to $1.6 billion and extension of the expiry date to December 2014. Amendment signed July 21, 2010. |
| June 2007 Board meeting | Pursuant to a Minister's directive dated June 11, 2007, approved a loan for up to $950 million for refinancing debt issued to OEFC and a loan for up to $500 million for general corporate requirements. | Structured to provide advances in tranches. The ability to draw on the refinancing facility to expire on Dec 31, 2009, and the general corporate requirements facility expired on March 31, 2008 (OPG has fully drawn on this facility). Each advance shall have a term up to 10 years. The interest rate is based on the Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement for the general corporate requirements signed on June 14, 2007.<br>Loan agreement for the refinancing maturing debt signed on July 6, 2007. |
| April 2006 Board meeting | Subject to receiving a Minister's directive, approved a loan for up to $400 million for the Portlands project and a loan for up to $50 for the Lac Seul project. | Structured to provide advances in tranches over a 3 year period. Each advance shall have a term as may be determined by the Chief Executive Officer of OEFC or his/her designate. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directives dated October 25, 2006.<br>Loan agreements for the Portlands and Lac Seul projects signed on December 6, 2006. |
| September 2005 Board meeting | Pursuant to the Minister's Directive dated August 18, 2005, approved loan for up to $1 billion for the Niagara Tunnel project. | Structured to provide advances in tranches over a 5 year period commencing in 2005. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Loan agreement signed on September 21, 2005. |

| Timing | Action | Details |
|---|---|---|
| September 2005 Board meeting (cont'd) | Subject to receiving a Minister's Directive, approved a loan for up to $95 million for the Thunder Bay conversion. | Structured to provide advances in tranches over a 2 year period commencing late 2005 or early 2006. Terms of each advance not to exceed 10 years. Interest based on Government of Canada benchmark bond yield plus a spread determined by OEFC.<br><br>Minister's Directive dated September 26, 2005. Loan agreement signed on November 14, 2005. In June 2006 the Government revoked its Directive to OPG on the Thunder Bay conversion project. OEFC and OPG terminated the loan agreement on September 29, 2006. |
| June 2005 Board meeting | OEFC Board was advised that OPG had approached OFA/OEFC to get funding indications for Niagara Tunnel Project.<br><br>While the government had provided overall support for the Niagara Tunnel Project, OEFC Board advised that staff would be coming back to the board to request a loan once a directive had been obtained | |
| March 2005 Board meeting | Pursuant to a Minister's Directive, $600 million in loans was approved to address OPG operating cash flow funding requirements from April 1, 2005 to March 31, 2006 | Structured to provide for drawdowns in 1 or more tranches at market rates for terms ranging from 3 to 7 years. Rates determined by OEFC. In May 2005, OPG borrowed $400 million, for a 7 year term at 5.715% (spread of 1.75% over the respective Canada bond) |
| | Loan approval for $98 million to OPG for a 5 year term commencing September 22, 2005 | Loan to offset interest payments on loans due that day and to be extended at market rates determined by OEFC.<br><br>Subsequently, OPG declined this loan due to higher than expected revenues. |
| December 2004 Board meeting | Extend $250 million March 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Extend $250 million September 22, 2005 debt maturity for another 5 years | Original average 5.62% borrowing cost maintained for extended loan |
| | Loan $95 million to OPG for a 5 year term commencing Mar. 22, 2005 | Loan to offset interest payments on loans due that day and 5.62% rate used for new loan |

## OPG Debt Maturity Schedule (at September 17, 2018):

| Maturity Date | Coupon Rate (%) | Amount ($ m) |
|---|---|---|
| Oct 22, 2018 | 6.325 | 20 |
| Jan 22, 2019 | 6.178 | 40 |
| Mar 22, 2019 | 5.651 | 100 |
| Apr 22, 2019 | 5.635 | 75 |
| Jul 22, 2019 | 5.184 | 65 |
| Oct 22, 2019 | 4.857 | 85 |
| Jan 22, 2020 | 4.618 | 50 |
| Mar 22, 2020 | 4.679 | 230 |
| Apr 22, 2020 | 4.954 | 65 |
| Jul 22, 2020 | 4.658 | 35 |
| Sep 22, 2020 | 4.391 | 230 |
| Oct 22, 2020 | 4.094 | 50 |
| Jan 22, 2021 | 4.573 | 40 |
| Apr 22, 2021 | 4.633 | 35 |
| Jul 22, 2021 | 4.152 | 50 |
| Oct 22, 2021 | 3.985 | 60 |
| Jan 22, 2022 | 3.583 | 40 |
| Apr 22, 2022 | 3.521 | 35 |
| Jul 22, 2022 | 2.981 | 45 |
| Oct 22, 2022 | 3.163 | 30 |
| Jan 22, 2023 | 3.27 | 20 |
| Apr 22, 2023 | 2.961 | 20 |
| Nov 22, 2026 | 3.037 | 50 |
| Mar 22, 2041 | 5.397 | 150 |
| Sep 22, 2041 | 4.74 | 150 |
| Apr 22, 2042 | 4.356 | 200 |
| Nov 22, 2046 | 4.028 | 50 |
| Feb 22, 2047 | 4.122 | 200 |
| Jun 22, 2047 | 3.648 | 100 |
| Aug 22, 2047 | 3.858 | 100 |
| Sep 22, 2047 | 4.066 | 400 |
| Jan 22, 2048 | 3.874 | 200 |
| Mar 22, 2048 | 3.997 | 400 |
| **Total Outstanding** | | **3,420.0** |

**Status of Project Financing (at September 17, 2018):**

| Project | Amount Authorized under Loan Agreement | Total Borrowing to Date | Expiry Date of Loan Agreement | Status of Project |
|---|---|---|---|---|
| **Corporate Credit Facility** | $2.35 billion | $1,400 million | Dec 31, 2018 | - |
| **Niagara Tunnel** | $1.6 billion | $1,065 million | Dec 30, 2014 | Completed |
| **Portlands** | $400 million | $390 million | Dec 29, 2009 | Completed |
| **Lac Seul** | $50 million | $50 million | Dec 29, 2009 | Completed |
| **Lower Mattagami** | $700 million | - | June 30, 2016 | Completed |

**Prepared by:**
**Electricity Finance Branch and Capital Market Division**
**September 17, 2018**

*Source: MOF Questions Reply*

***Below is the financial impact of the gain on the sale of OPG's head office property that is included in the P***

| $ millions | |
|---|---|
| Earnings Before Tax (EBT) | |
| Assumed Proceeds | 400 |
| Assumed Net Book Value | -104 |
| **EBT- Other Income** | **296** |
| | |
| Income Tax Expense | 74 |
| **Net Income Impact** | **223** |

*Province's fiscal year ended March 31, 2018

| Fiscal Year | 2016-17 | 2017-18* |
|---|---|---|
| **Net Income Atributable to Shareholder** | **379** | **702** |
| | | |
| **Non Income Tax PILs** | | |
| GRC: Payable to OEFC & NPC | 314 | 332 |
| Property Tax Payable to OEFC | 14 | 18 |
| **Total Non Income Tax PILs** | **329** | **350** |
| | | |
| **Income Tax PILs** | **92** | **166** |
| | | |
| **Total Shareholder Return** | **800** | **1,218** |
| | | |
| **EBT** | **471** | **868** |

*Sources: 2017 OPG BP*

** Source: MOF Questions Reply*

| Budget 2016 / Fiscal Plan ($M) | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 471 | 586 | 673 | 705 |
| Income Tax PILs | 224 | 159 | 182 | 108 |
| Earnings Before Tax | **695** | **745** | **855** | **812** |
| **OPG 2017-19 Business Plan ($M)** | | | | |
| Net Income After Tax (Adjusted) | 379 | 480 | 678 | 726 |
| Income Tax PILs | 92 | 92 | 135 | 170 |
| Earnings Before Tax | **471** | **572** | **813** | **896** |

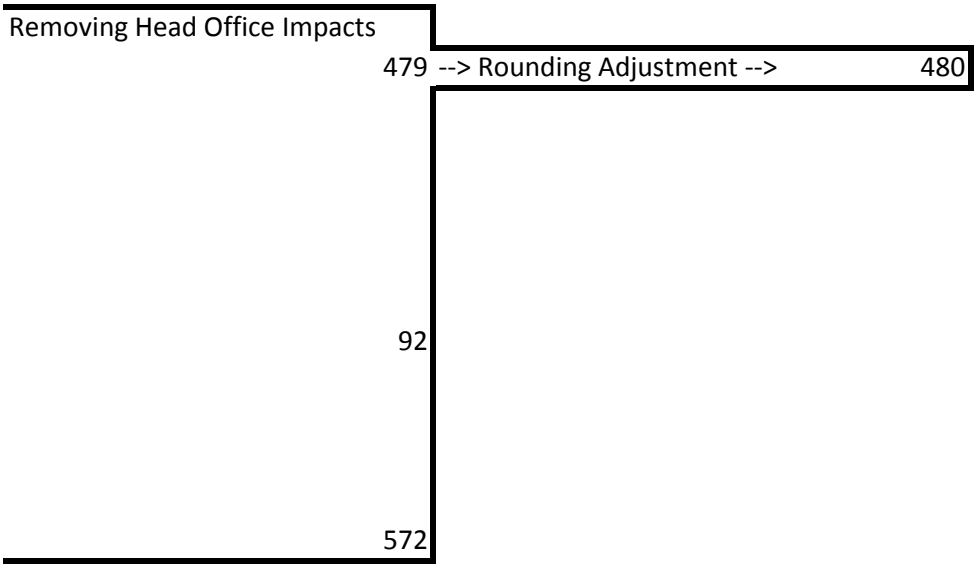
| | | | | |
|---|---|---|---|---|
| **EBT Variance to Fiscal Plan** | -224 | -173 | -42 | 84 |

*province's fiscal year ended March 31, 2018:*

| 2018-19 | 2019-20 | 2020-21 |
|---|---|---|
| 678 | 726 | |
| 344 | 343 | |
| 19 | 19 | |
| 363 | 362 | |
| 135 | 170 | |
| 1,176 | 1,258 | |
| 813 | 896 | |

**Backing Out on Gain on Sale of OPG's Head Office**

| | 2017-18 | Adjustments |
|---|---|---|
| Net Income Atributable tc | 702 | 223 |
| Income Tax PILs | 166 | 74 |
| EBT | 868 | 296 |


Removing Head Office Impacts
479
--> Rounding Adjustment -->
480
92
572

| OPG Outlook Forecast | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income Attributable to Shareholder | 349 | 702 | 678 |
| Income Tax (Income Tax PILs) | 96 | 166 | 135 |
| **EBT** | **445** | **868** | **813** |

## Forecast Backups

| *OPG 2016-17 Net Income Calculation (USGAAP) ($M)* | | | |
|---|---|---|---|
| | **Q1 2016[1]** | **2016** | **Q1 2017[1]** |
| **Net Income Attributable to Shareholder** | 123 | 438 | 34 |
| | Source | Source | Source |
| *Note: 2016 OPG net income is from OPG's 2017 BP (to be updated when 2016FS are released); Q* | | | |

| OPG 2017-19 Business Plan Projections ($M) | 2015 | 2016 | 2017 |
|---|---|---|---|
| OPG Business Plan Net Income (calendar) | 402 | 438 | 508 |

| | 2015-16 | 2016-17 |
|---|---|---|
| OPG Business Plan Net Income (Fiscal) | 411 | 456 |
| OPG 2016 BP EBT (sourced from Energy FPC) | 383 | 406 |

| Source: 2017 OPG BP Fiscal Year | 2016-17 |
|---|---|
| **Net Income Atributable to Shareholder** | **349** |
| **Non Income Tax PILs** | |
| GRC: Payable to OEFC & NPC | 321 |
| Property Tax Payable to OEFC | 15 |
| **Total Non Income Tax PILs** | **336** |
| **Income Tax PILs** | **96** |
| **Total Shareholder Return** | **781** |
| **EBT** | **445** |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 |
| Income Taxes | 89 | 120 | 250 |
| **Earnings Before Tax** | **389** | **220** | **890** |

| 2019-20 | 2020-21 |
|---|---|
| 726 | 913.25* |
| 170 | N/A |
| **896** | **N/A** |

| |
|---|
| **Fiscal Year 2016-17** |
| **349** |

*1 2016 figures are from OPG's preliminary Q1 2016 financial reports; and Q1 2017 are 2017 BP estimates*

| 2018 | 2019 | 2020 | 2021 | |
|---|---|---|---|---|
| 679 | 729 | 883 | 1004 | Source |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | |
|---|---|---|---|---|
| 551 | 692 | 768 | 913 | EFB Calculation |
| 939 | 841 | | | Source |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|
| **702** | **678** | **726** | |
| 332 | 344 | 343 | |
| 18 | 19 | 19 | |
| **350** | **363** | **362** | |
| **166** | **135** | **170** | |
| **1,218** | **1,176** | **1,258** | |
| **868** | **813** | **896** | |

| 2018-19 |
|---|

| |
|---|
| 575 |
| 140 |
| **715** |

| OPG Outlook Forecast | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income | 291 | 335 | 551 | 692 |
| Income Tax | 92 | 120 | 388 | 150 |
| **EBT** | **383** | **455** | **939** | **841** |

## Forecast Backups

| *OPG 2015-16 Net Income Calculation (USGA* | | | |
|---|---|---|---|
| | **Q1 2015[1]** | **2015** | **Q1 2016[1]** |
| **Net Income Attributable to Shareholder** | | | |

*Note: 2015 OPG net income is from OPG's 2015 annual report; Q1 2015 and Q1 2016 figures are from OPG's*

| OPG New Business Plan Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| OPG Business Plan Net Income (Fiscal) | 404 | 435 | 551 | 692 |
| OPG New BP EBT | 383 | 406 | 939 | 841 |
| | **2015** | **2016** | **2017** | **2018** |
| OPG Business Plan Net Income | 402 | 411 | 508 | 679 |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 | 575 |
| Income Taxes | 89 | 120 | 250 | 140 |
| **Earnings Before Tax** | **389** | **220** | **890** | **715** |

| 2019-20 | 2020-21 |
|---|---|
| 768 | 913 |
| N/A | N/A |
| **N/A** | **N/A** |

***AP) ($M)***

| | Q1 2015[1] | 2015 | Q1 2016[1] | Fiscal Year 2015-16 |
|---|---|---|---|---|
| | 234 | 402 | 123 | **291** |

*s preliminary Q1 2016 financial reports*

| 2019-20 | 2020-21 |
|---|---|
| 768 | 913 |

| 2019 | 2020 | 2021 |
|---|---|---|
| 729 | 883 | 1004 |

| OPG Outlook Forecast | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income | 291 | 335 | 551 | 692 |
| Income Tax | 92 | 120 | 388 | 150 |
| **EBT** | **383** | **455** | **939** | **841** |

## Forecast Backups

| *OPG 2015-16 Net Income Calculation (USGA* | | | |
|---|---|---|---|
| | **Q1 2015[1]** | **2015** | **Q1 2016[1]** |
| **Net Income Attributable to Shareholder** | | | |

*Note: 2015 OPG net income is from OPG's 2015 annual report; Q1 2015 and Q1 2016 figures are from OPG's*

| OPG New Business Plan Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| OPG Business Plan Net Income (Fiscal) | 404 | 435 | 551 | 692 |
| OPG New BP EBT | 383 | 406 | 939 | 841 |
| | **2015** | **2016** | **2017** | **2018** |
| OPG Business Plan Net Income | 402 | 411 | 508 | 679 |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 | 575 |
| Income Taxes | 89 | 120 | 250 | 140 |
| **Earnings Before Tax** | **389** | **220** | **890** | **715** |

| 2019-20 | 2020-21 |
|---|---|
| 768 | 913 |
| N/A | N/A |
| **N/A** | **N/A** |

***AP) ($M)***

| | Q1 2015[1] | 2015 | Q1 2016[1] | Fiscal Year 2015-16 |
|---|---|---|---|---|
| | 234 | 402 | 123 | **291** |

*s preliminary Q1 2016 financial reports*

| 2019-20 | 2020-21 |
|---|---|
| 768 | 913 |

| 2019 | 2020 | 2021 |
|---|---|---|
| 729 | 883 | 1004 |

| OPG Outlook Forecast | 2016-17 | 2017-18 | 2018-19 |
|---|---|---|---|
| Net Income Attributable to Shareholder | 349 | 702 | 678 |
| Income Tax (Income Tax PILs) | 96 | 166 | 135 |
| **EBT** | **445** | **868** | **813** |

## Forecast Backups

| *OPG 2016-17 Net Income Calculation (USGAAP) ($M)* | | | |
|---|---|---|---|
| | **Q1 2016[1]** | **2016** | **Q1 2017[1]** |
| **Net Income Attributable to Shareholder** | 123 | 438 | 34 |
| | Source | Source | Source |
| *Note: 2016 OPG net income is from OPG's 2017 BP (to be updated when 2016FS are released); Q* | | | |

| OPG 2017-19 Business Plan Projections ($M) | 2015 | 2016 | 2017 |
|---|---|---|---|
| OPG Business Plan Net Income (calendar) | 402 | 438 | 508 |

| | 2015-16 | 2016-17 |
|---|---|---|
| OPG Business Plan Net Income (Fiscal) | 411 | 456 |
| OPG 2016 BP EBT (sourced from Energy FPC) | 383 | 406 |

| Source: 2017 OPG BP Fiscal Year | 2016-17 |
|---|---|
| **Net Income Atributable to Shareholder** | **349** |
| **Non Income Tax PILs** | |
| GRC: Payable to OEFC & NPC | 321 |
| Property Tax Payable to OEFC | 15 |
| **Total Non Income Tax PILs** | **336** |
| **Income Tax PILs** | **96** |
| **Total Shareholder Return** | **781** |
| **EBT** | **445** |

| OPG's January Preliminary Planning Projections ($M) | 2015-16 | 2016-17 | 2017-18 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Net Income After Tax (Adjusted) | 300 | 100 | 640 |
| Income Taxes | 89 | 120 | 250 |
| **Earnings Before Tax** | **389** | **220** | **890** |

| 2019-20 | 2020-21 |
|---|---|
| 726 | 913.25* |
| 170 | N/A |
| **896** | **N/A** |

| |
|---|
| **Fiscal Year 2016-17** |
| **349** |

*1 2016 figures are from OPG's preliminary Q1 2016 financial reports; and Q1 2017 are 2017 BP estimates*

| 2018 | 2019 | 2020 | 2021 | |
|---|---|---|---|---|
| 679 | 729 | 883 | 1004 | Source |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 | |
|---|---|---|---|---|
| 551 | 692 | 768 | 913 | EFB Calculation |
| 939 | 841 | | | Source |

| 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|
| **702** | **678** | **726** | |
| 332 | 344 | 343 | |
| 18 | 19 | 19 | |
| **350** | **363** | **362** | |
| **166** | **135** | **170** | |
| **1,218** | **1,176** | **1,258** | |
| **868** | **813** | **896** | |

| 2018-19 |
|---|

| |
|---|
| 575 |
| 140 |
| **715** |

ONTARIO POWER GENERATION

News
from Ontario Power Generation

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Aug. 9, 2018

# OPG REPORTS 2018 SECOND QUARTER FINANCIAL RESULTS

*OPG receives ten-year operating license extension for the Pickering generating station - Agrees to acquire Eagle Creek Renewable Energy*

**Toronto:** – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $121 million for the second quarter of 2018, compared to $303 million for the same quarter in 2017. Net income for the second quarter of 2017 included a one-time after-tax gain of $283 million on the sale of OPG's head office property.

"As Ontario's publicly-owned low-cost electricity generator, we are pleased to report our second quarter results that provided a strong return for our shareholder, the Province of Ontario. We remain focused on continuing to be Ontario's lowest cost electricity producer and driving value from our public assets for the benefit of our owners, the people of Ontario," said Jeff Lyash, OPG President and CEO. "We are also pleased that the Canadian Nuclear Safety Commission has granted OPG a ten-year operating license to allow the Pickering station to operate commercially until the end of 2024 and then conduct the work needed through to 2028 to place the station in a safe state as the initial part of the decommissioning process. This public asset provides a reliable supply of low-cost electricity for up to 1.5 million Ontario homes each day," Lyash added. "During his visit to the Pickering station in June, Premier Ford confirmed his ongoing support for Pickering's continued operation and the thousands of jobs across Ontario that depend on the station."

"We are also very pleased to announce that we have signed a deal to acquire Eagle Creek Renewable Energy, an operator of small hydropower facilities in the United States." Lyash continued, "By expanding our core business with this purchase, OPG is capitalizing on a new growth opportunity by making an investment in a strategic set of hydroelectric assets that will produce an attractive return for our shareholder, the Province of Ontario. This acquisition will be financed without the use of taxpayer funds and will have no impact on Ontario's electricity customers." Lyash added, "As Ontario's public electricity generator, we have been stewards of hydroelectric assets for more than a century and we are proud to continue that legacy with this acquisition."

"Also announced this quarter, the Darlington Nuclear Station is poised to become the world's first large-scale commercial supplier of molybdenum-99, a life-saving medical isotope that is used in over 30 million medical treatments worldwide each year," added Lyash. "Darlington's Canada Deuterium Uranium (CANDU) reactors will allow for a continuous supply of this medical isotope that hospitals and health providers have had to import from Europe, Africa and Australia since Canada's National Research Universal reactor ceased regular production in 2016."

The Company's net income for the second quarter of 2018 was favourably impacted by the new regulated prices for OPG's nuclear and most of its hydroelectric generation, resulting from the Ontario Energy Board's (OEB) decision on OPG's application for new regulated prices for the 2017-2021 period issued in December 2017. Partially offsetting the increase in earnings due to the new regulated prices, nuclear electricity generation in the second quarter of 2018 was lower compared to the same period in 2017, as expected, due to a higher concentration of the year's planned outage days at the Pickering Generating Station (GS) in the second quarter of 2018, compared to 2017, in line with the station's cyclical maintenance schedule.

Taking into account the impact of the new regulated prices, OPG continues to provide electricity at a price that is approximately 40 per cent less than the average of other generators. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

The Company successfully closed a $450 million green bond offering in June 2018, a first-of-its kind financing for the Canadian energy sector. The proceeds from the offering will be used to finance eligible hydroelectric projects as part of OPG's clean power generating fleet.

**Acquisition of Eagle Creek Renewable Energy**

OPG has signed a purchase and sale agreement to acquire 100 per cent of the equity of Eagle Creek Renewable Energy LLC (Eagle Creek), an operator of small hydropower facilities in the United States, for US$298 million, subject to customary working capital and other adjustments. The acquisition will have no impact on electricity customers in Ontario and will lead to higher returns for OPG's shareholder, the Province of Ontario.

Eagle Creek currently owns and operates 63 small hydropower facilities representing 216 megawatts (MW) of capacity primarily located in the U.S. Northeast and Midwest. Eagle Creek also has ownership interests in 13 other hydroelectric assets and two solar facilities in New England representing 10 MW of capacity.

Pending U.S. regulatory approvals and final closing, Eagle Creek will become a wholly-owned subsidiary of OPG. OPG's operations in Ontario will remain a separate business entity, primarily regulated by the OEB.

## Generation and Operating Performance

Electricity generated during the three months ended June 30, 2018 was 17.2 terawatt hours (TWh), compared to 18.0 TWh for the same quarter in 2017. Total electricity generated during the six months ended June 30, 2018 decreased to 36.0 TWh from 36.6 TWh for the same period in 2017.

*Regulated – Nuclear Generation Segment*

Lower nuclear generation of 0.7 TWh and 0.3 TWh during the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was primarily due to a higher number of planned outage days at the Pickering GS. The decrease was expected and partially offset by fewer planned outage days at the Darlington GS during the first quarter of 2018.

For the three months ended June 30, 2018, the unit capability factor for the operating units at the Darlington GS was 67.4 per cent, compared to 64.6 per cent for the same quarter in 2017. For the six months ended June 30, 2018, the unit capability factor for the operating units at the Darlington GS was 81.9 per cent, compared to 74.9 per cent for the same period in 2017. The increase for the three months ended June 30, 2018 was primarily due to fewer unplanned outage days at the station. For the six months ended June 30, 2018, the increase was due to fewer planned outage days at the station during the first quarter of 2018.

At the Pickering GS, the unit capability factor decreased to 71.3 per cent and 72.9 per cent for the three and six month periods ended June 30, 2018, respectively, compared to 84.2 per cent and 81.4 per cent for the same periods in 2017. The decrease was expected and primarily due to a higher number of planned outage days in the station's cyclical maintenance schedule in the first half of 2018.

Fewer outage days are planned for the Regulated – Nuclear Generation in the second half of the year in 2018, compared to the same period in 2017.

*Regulated – Hydroelectric Segment*

Lower generation from the regulated hydroelectric stations of 0.6 TWh and 0.9 TWh during the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was primarily due to lower water flows on most river systems in eastern and northern Ontario.

The availability of 88.6 per cent at these stations in the second quarter of 2018 was lower than 90.1 per cent for the same quarter in 2017. For the six months ended June 30, 2018, the availability of the stations decreased to 87.9 per cent, from 89.8 per cent for the same period in 2017. The decrease in the availability was primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

*Contracted Generation Portfolio Segment*

Higher generation from the Contracted Generation Portfolio of 0.5 TWh and 0.6 TWh during the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was primarily due to lower electricity generation forgone as a result of surplus baseload generation conditions.

The availability of these hydroelectric stations for the three months ended June 30, 2018 was 86.5 per cent, compared to 81.4 per cent for the same period in 2017. The stations' availability for the six months ended June 30, 2018 was 83.3 per cent, compared to 82.5 per cent for the same period in 2017. The increase was primarily due to a lower number of unplanned outage days at the northeastern Ontario regions' contracted hydroelectric stations.

In 2014, OPG converted one generating unit at the Thunder Bay GS from coal-fired generation to advanced biomass fuelled generation, under an Energy Supply Agreement (ESA) with the Independent Electricity System Operator (IESO). In July 2018, OPG and the IESO reached an agreement to terminate the ESA for the Thunder Bay GS, effective June 30, 2018. The termination agreement was determined to be the most cost effective alternative for electricity consumers, and allowed OPG to avoid additional repair costs that would have been necessary to continue to operate the Thunder Bay GS for the remainder of the ESA term to January 2020. OPG will work with affected employees and other stakeholders to ensure that all parties are treated fairly and respectfully as part of the station's closure. The station's closure is not expected to have a material impact on OPG's financial results.

*Total Generating Cost*

The Enterprise Total Generating Cost per megawatt hour (MWh) for the three months ended June 30, 2018 was $55.78, compared to $48.72 for the same period in 2017. The Enterprise Total Generating Cost per MWh for the six months ended June 30, 2018 was $52.71, compared to $48.35 for the same period in 2017. The increase in 2018 was mainly due to the favourable impact of higher water flows on hydroelectric electricity generation adjusted for surplus baseload conditions in 2017.

**Generation Development**

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during the second quarter of 2018 included the following:

*Darlington Refurbishment*

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. In early May 2018, OPG completed the second major segment of the Unit 2 refurbishment, the removal of existing reactor components, and transitioned into the third major segment, the installation and reassembly of reactor components. Following the completion of inspections and cleaning on the reactor face, OPG commenced the reassembly of Unit 2 in July 2018. The Darlington Refurbishment, the execution of which began in 2016, project continues to track on schedule and to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG continues to progress with the planning and prerequisite activities for the refurbishment of Unit 3, incorporating the experience learned to date on Unit 2's execution, and is continuing to enter into commitments to procure major components that require long lead times. The Unit 3 refurbishment is expected to commence upon the return to service of Unit 2. As of June 30, 2018, $169 million has been invested in planning and prerequisite activities related to the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $4.9 billion as at June 30, 2018.

*Ranney Falls Hydroelectric GS*

In the second quarter of 2018, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. Construction continues with concrete placement of the expanded forebay, powerhouse and spillway. Sectional gates and head gates installation, substation construction, and turbine and generator unit fabrication are in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

| *(millions of dollars – except where noted)* | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Revenue | **1,282** | 1,146 | **2,689** | 2,322 |
| Fuel expense | **166** | 178 | **321** | 333 |
| Operations, maintenance and administration | **743** | 711 | **1,465** | 1,419 |
| Depreciation and amortization | **198** | 172 | **384** | 339 |
| Other expenses (gains), net [1] | **31** | (335) | **(196)** | (288) |
| Income before interest and income taxes | **144** | 420 | **715** | 519 |
| Net interest expense | **18** | 16 | **37** | 35 |
| Income tax expense | **-** | 97 | **13** | 109 |
| Net income | **126** | 307 | **665** | 375 |
| **Net income attributable to the Shareholder** | **121** | 303 | **656** | 367 |
| **Net income attributable to non-controlling interest** [2] | **5** | 4 | **9** | 8 |
| ***Income before interest and income taxes*** | | | | |
| Electricity generating business segments | **172** | 80 | **496** | 219 |
| Regulated – Nuclear Waste Management | **(32)** | (40) | **(65)** | (87) |
| Fair Hydro Trust | **8** | - | **12** | - |
| Other | **(4)** | 380 | **272** | 387 |
| Total income before interest and income taxes | **144** | 420 | **715** | 519 |
| ***Cash flow*** | | | | |
| Cash flow provided by operating activities | **413** | 89 | **639** | 257 |
| ***Electricity generation (TWh)*** | | | | |
| Regulated – Nuclear Generation | **8.6** | 9.3 | **19.0** | 19.3 |
| Regulated – Hydroelectric | **7.6** | 8.2 | **15.3** | 16.2 |
| Contracted Generation Portfolio [3] | **1.0** | 0.5 | **1.7** | 1.1 |
| Total electricity generation | **17.2** | 18.0 | **36.0** | 36.6 |
| ***Nuclear unit capability factor (per cent)*** [4] | | | | |
| Darlington Nuclear GS | **67.4** | 64.6 | **81.9** | 74.9 |
| Pickering Nuclear GS | **71.3** | 84.2 | **72.9** | 81.4 |
| ***Availability (per cent)*** | | | | |
| Regulated – Hydroelectric | **88.6** | 90.1 | **87.9** | 89.8 |
| Contracted Generation Portfolio – hydroelectric stations | **86.5** | 81.4 | **83.3** | 82.5 |
| ***Equivalent forced outage rate*** | | | | |
| Contracted Generation Portfolio – thermal stations | **1.4** | 2.7 | **0.8** | 7.8 |
| *Enterprise Total Generating Cost (TGC) per MWh ($/MWh) for the three and six months ended June 30, 2018 and June 30, 2017 ($/MWh)* [5] | **55.78** | 48.72 | **52.71** | 48.35 |
| *Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended June 30, 2018 and December 31, 2017 (%)* [5] | | | **9.7** | 7.6 |

[1] For the six months ended June 30, 2018, includes the pre-tax gain on the sale of the former Lakeview GS site. For the three and six month periods ended June 30, 2017, includes the pre-tax gain on the sale of OPG's head office property.

[2] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[3] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[4] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[5] Enterprise TGC per MWh and ROE Excluding AOCI are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the three and six month periods ended June 30, 2018, in the sections *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, *Highlights – Enterprise Total Generating Cost per MWh*, and *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s unaudited interim consolidated financial statements and Management's Discussion and Analysis as at and for the three and six month periods ended June 30, 2018 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

For further information, please contact: Investor Relations 416-592-6700
webmaster@opg.com

Media Relations 416-592-4008
1-877-592-4008

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# ONTARIO POWER GENERATION INC.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## 2018 SECOND QUARTER REPORT

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ONTARIO POWER GENERATION

# ONTARIO POWER GENERATION INC.
# MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and six months ended June 30, 2018, compared to the same periods in 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, Annual Information Form, and MD&A as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP instead of International Financial Reporting Standards (IFRS). In April 2018, the OSC approved an exemption which allows the Company to continue to apply US GAAP up to January 1, 2024. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2024. For details, refer to the section, *Changes in Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP.* This MD&A is dated August 8, 2018.

## FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management*, and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, the *Ontario Fair Hydro Plan Act, 2017* (Fair Hydro Act) and forecasts of earnings, cash flows, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-

looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

## THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at June 30, 2018, OPG's electricity generation portfolio had an in-service capacity of 16,218 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS), and OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP. Income from these leased stations is included as revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2017 annual MD&A in the section, *Business Segments*.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

### In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of June 30, 2018 and December 31, 2017 was as follows:

| | As at | |
|---|---|---|
| *(MW)* | **June 30 2018** | **December 31 2017** |
| Regulated – Nuclear Generation [1] | **5,728** | 5,728 |
| Regulated – Hydroelectric | **6,426** | 6,426 |
| Contracted Generation Portfolio [2] | **4,064** | 4,056 |
| Total | **16,218** | 16,210 |

[1] The in-service generating capacity as of June 30, 2018 and December 31, 2017 excludes Unit 2 of the Darlington Nuclear GS (Darlington GS). The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the six months ended June 30, 2018, the total in-service capacity increased by 8 MW. The increase was due to the completion of the overhaul and upgrade of Unit 1 of the Harmon hydroelectric GS, which returned to service in the first quarter of 2018.

## HIGHLIGHTS

### Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results and summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to OPG's results during the three and six month periods ended June 30, 2018, compared to the same periods in 2017, are discussed below. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

| *(millions of dollars – except where noted)* | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Revenue | **1,282** | 1,146 | **2,689** | 2,322 |
| Fuel expense | **166** | 178 | **321** | 333 |
| Operations, maintenance and administration | **743** | 711 | **1,465** | 1,419 |
| Depreciation and amortization | **198** | 172 | **384** | 339 |
| Other expenses (gains), net | **31** | (335) | **(196)** | (288) |
| Income before interest and income taxes | **144** | 420 | **715** | 519 |
| Net interest expense | **18** | 16 | **37** | 35 |
| Income tax expense | **-** | 97 | **13** | 109 |
| Net income | **126** | 307 | **665** | 375 |
| Net income attributable to the Shareholder | **121** | 303 | **656** | 367 |
| Net income attributable to non-controlling interest [1] | **5** | 4 | **9** | 8 |
| *Electricity production (TWh)* [2] | **17.2** | 18.0 | **36.0** | 36.6 |
| *Cash flow* | | | | |
| Cash flow provided by operating activities | **413** | 89 | **639** | 257 |
| *Segment Results* | | | | |
| Regulated – Nuclear Generation | **(84)** | (169) | **(9)** | (287) |
| Regulated – Hydroelectric | **178** | 172 | **349** | 352 |
| Contracted Generation Portfolio | **78** | 77 | **156** | 154 |
| Total electricity generating business segments | **172** | 80 | **496** | 219 |
| Regulated – Nuclear Waste Management | **(32)** | (40) | **(65)** | (87) |
| Fair Hydro Trust | **8** | - | **12** | - |
| Other | **(4)** | 380 | **272** | 387 |
| Income before interest and income taxes | **144** | 420 | **715** | 519 |

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Second Quarter

Net income attributable to the Shareholder was $121 million for the second quarter of 2018, a decrease of $182 million compared to the same quarter in 2017. Income before interest and income taxes for the second quarter of 2018 was $144 million, a decrease of $276 million compared to the same quarter in 2017. The following summarizes the significant factors which contributed to the variance:

*Significant factors that reduced income before interest and income taxes:*

- A pre-tax gain on the sale of OPG's head office premises and associated parking facility of $378 million recorded in the second quarter of 2017. The sale of these non-core real estate assets was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), the proceeds from the disposition, net of prescribed deductions under the Trillium Trust Act, were transferred into the Province's Consolidated Revenue Fund in March 2018 in the form of a special dividend.
- Lower electricity generation of 0.7 terawatt hours (TWh) from the Regulated – Nuclear Generation segment, resulting in lower revenue of approximately $45 million. The lower electricity generation from the segment reflected a higher concentration of the year's planned outage days at the Pickering Nuclear GS (Pickering GS) in the second quarter of 2018, compared to 2017, as part of the station's cyclical maintenance schedule.
- Higher OM&A expenses of $32 million, mainly reflecting services and materials costs associated with increased outage activity at the Pickering GS during the second quarter of 2018.
- Higher depreciation and amortization expenses of $12 million, excluding amortization expense related to the recovery of OEB-authorized regulatory variance and deferral account (regulatory account) balances, mainly due to new assets in service.

*Significant factor that increased income before interest and income taxes:*

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $178 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.

Net interest expense increased by $2 million during the second quarter of 2018, compared to the same quarter in 2017, primarily due to a lower amount of interest costs deferred in regulatory accounts, partially offset by a higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures.

Income tax expense decreased by $97 million for the three months ended June 30, 2018, compared to the same period in 2017. The decrease was primarily due to lower income before taxes and a higher amount of deferred income tax expense recorded as a regulatory asset.

Year-To-Date

Net income attributable to the Shareholder was $656 million for the first six months of 2018, an increase of $289 million compared to the same period in 2017. Income before interest and income taxes for the first six months of 2018 was $715 million, an increase of $196 million compared to the same period in 2017. The following summarizes the significant factors which contributed to the variance:

*Significant factors that increased income before interest and income taxes:*

- Higher revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $388 million, reflecting the impact of new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order on OPG's application for new regulated prices.

- A pre-tax gain on the sale of the former Lakeview GS site of $273 million recognized in net income upon completion of the transaction in the first quarter of 2018. The sale of this non-core real estate asset was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from the disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of the designated proceeds under the Trillium Trust Act to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on the sale of $205 million and is working with the Ontario Ministry of Finance to finalize the amount.
- Higher earnings of $22 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

*Significant factors that reduced income before interest and income taxes:*

- A pre-tax gain on the sale of OPG's head office premises and associated parking facility of $378 million recorded in the second quarter of 2017.
- Lower electricity generation of 0.3 TWh from the Regulated – Nuclear Generation segment, resulting in lower revenue of approximately $20 million. The lower electricity generation from the segment reflected a higher concentration of the year's planned outage days at the Pickering GS in the first half of 2018, compared to 2017.
- Higher OM&A expenses of $46 million, mainly reflecting services and materials costs associated with increased outage activity at the Pickering GS during the first half of 2018.
- Higher depreciation and amortization expenses of $26 million, excluding amortization expense related to the recovery of the regulatory account balances, mainly due to new assets in service.

Net interest expense increased by $2 million for the six months ended June 30, 2018, compared to the same period in 2017, primarily due to a lower amount of interest costs deferred in regulatory accounts, partially offset by a higher amount of interest costs capitalized related to the Darlington Refurbishment project expenditures.

Income tax expense decreased by $96 million for the six months ended June 30, 2018, compared to the same period in 2017. The decrease was primarily due to a reduction in income taxes due to a refundable tax credit of $86 million and a higher amount of deferred income tax expense recorded as a regulatory asset, partially offset by the impact of higher income before taxes.

## Recent Developments

Acquisition of Eagle Creek Renewable Energy

On August 8, 2018, OPG entered into a purchase and sale agreement with Power Energy Eagle Creek, LLC and Hudson Clean Energy Partners LP to acquire 100 percent of the equity in Eagle Creek Renewable Energy LLC (Eagle Creek) for US dollars (USD) $298 million, subject to customary working capital and other adjustments. Eagle Creek is a hydropower platform, with 226 MW of capacity spread across 76 hydroelectric facilities and two solar facilities throughout the United States, and represents an opportunity to expand OPG's renewable generation portfolio to new geographies, with additional carbon-free generation aligning to OPG's strategic imperatives. The majority of facilities within Eagle Creek's fleet have operated as merchant based plants in the New England, Michigan and New York market areas. The acquisition of Eagle Creek is subject to receipt of final regulatory approvals, with closing expected to occur towards the end of 2018.

Continued Operations Plan for Pickering GS

OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In August 2017, OPG submitted a ten-year licence renewal application to the CNSC in line with the Company's plan to extend commercial operation of the station to December 31, 2024 and subsequently place the station in a safe storage state in 2028. The first public hearing for the licence renewal application took place in April 2018 and the final set of public hearings took place in June 2018. In August 2018, OPG obtained a ten-year operating licence renewal from the CNSC, which supports its continued operations plan for the Pickering GS to 2024.

On June 21, 2018, the newly elected Premier of Ontario confirmed the Province's commitment to the continued operation of the Pickering GS to 2024.

Collaboration for Production of Medical Isotopes

In June 2018, Canadian Nuclear Partners, a wholly-owned subsidiary of OPG, and BWX Technologies, Inc. (BWXT) announced a collaboration that will make the Darlington GS the first commercial nuclear power station worldwide to produce molybdenum-99 (Mo-99). Mo-99 is a parent isotope of technetium-99 (Tc-99m) used for skeletal, brain and organ imaging in order to detect and diagnose harmful diseases, including heart disease and cancer. The Canada Deuterium Uranium (CANDU) reactors at the Darlington GS allow for the insertion and removal of medical isotope targets while producing electricity, allowing for a continuous domestic supply of this critical medical isotope that is used in more than 30 million life-saving diagnostic and medical treatments worldwide each year. OPG will supply BWXT with Mo-99, which will be processed to produce Tc-99m. The plan to produce Mo-99 at the Darlington GS is subject to CNSC reviews and approvals. Subject to these reviews and approvals, OPG expects that production of Mo-99 will begin as early as the end of 2019.

Termination of Thunder Bay GS Energy Supply Agreement

On July 26, 2018, OPG reached an agreement with the Independent Electricity System Operator (IESO) to terminate the Energy Supply Agreement (ESA) for the advanced biomass fuelled generating unit at the Thunder Bay GS, effective June 30, 2018. The termination of the ESA was determined to be the most cost effective alternative for electricity consumers and allowed OPG to avoid additional repair costs that would have been necessary to continue to operate the Thunder Bay GS for the remainder of the ESA term to January 2020. The termination agreement provides for payments to OPG for the remainder of 2018 to allow for the orderly cessation of activities as part of the station's closure, including disposition of fuel inventories and fuel contracts. Under the terms of the termination agreement, OPG will propose, for IESO's review, a plan to make commercially reasonable efforts to mitigate the cost of advanced biomass fuel that had been committed to purchase for use at the Thunder Bay GS.

The termination of the ESA for the Thunder Bay GS did not impact OPG's financial results for the three and six months ended June 30, 2018. The station's closure is not expected to have a material impact on OPG's financial results in future periods.

Green Bond Offering

In June 2018, OPG issued an inaugural green bond offering under its existing Medium Term Note Program. The $450 million 30-year bonds were priced with a coupon interest rate of 3.84 percent and represent the first green bond issuance in the Canadian energy sector. The proceeds are to be used to finance eligible hydroelectric projects under OPG's Green Bond Framework.

Power Workers' Union Collective Agreement

The Power Workers' Union (PWU) represents approximately 4,700 regular employees at OPG, or approximately 52 percent of OPG's regular workforce as at June 30, 2018. The governing collective agreement between OPG and the PWU expired on March 31, 2018. On June 5, 2018, the parties reached a tentative agreement for the renewal of the collective agreement. The tentative agreement is subject to ratification by the PWU membership. The outcome of the ratification process is expected to be known in August 2018.

## Electricity Generation

Electricity generation for the three and six month periods ended June 30, 2018 and 2017 was as follows:

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(TWh)* | **2018** | **2017** | **2018** | **2017** |
| Regulated – Nuclear Generation | **8.6** | 9.3 | **19.0** | 19.3 |
| Regulated – Hydroelectric | **7.6** | 8.2 | **15.3** | 16.2 |
| Contracted Generation Portfolio [1] | **1.0** | 0.5 | **1.7** | 1.1 |
| Total OPG electricity generation | **17.2** | 18.0 | **36.0** | 36.6 |
| Total electricity generation by other generators in Ontario [2] | **17.4** | 16.5 | **36.5** | 35.1 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 0.8 TWh during the second quarter of 2018, compared to the same quarter in 2017, and by 0.6 TWh during the six months ended June 30, 2018, compared to the same period in 2017. This decrease was due to lower electricity generation from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments, partially offset by higher electricity generation from the Contracted Generation Portfolio segment.

The decrease in electricity generation of 0.7 TWh and 0.3 TWh from the Regulated – Nuclear Generation segment for the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was expected and primarily due to an increase in the number of planned outage days at the Pickering GS. The decrease in electricity generation from the Regulated – Nuclear Generation segment for the six months ended June 30, 2018 was partially offset by fewer planned outage days at the Darlington GS during the first quarter of 2018. The increase in the number of planned outage days at the Pickering GS reflected a higher concentration of the year's planned outage activity at the station in the first half of 2018, compared to 2017, as part of the station's cyclical maintenance schedule. Fewer outage days are planned for the Regulated – Nuclear Generation segment in the second half of the year in 2018, compared to the same period in 2017.

The decrease in electricity generation of 0.6 TWh and 0.9 TWh from the Regulated – Hydroelectric segment for the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was primarily

due to lower water flows on most river systems in eastern and northern Ontario, partially offset by lower electricity generation forgone as a result of SBG conditions.

The increase in electricity generation of 0.5 TWh and 0.6 TWh from the Contracted Generation Portfolio segment for the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, was primarily due to lower electricity generation forgone as a result of SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and six month periods ended June 30, 2018, Ontario's electricity demand as reported by the IESO was 31.9 TWh and 66.9 TWh, respectively, compared to 30.6 TWh and 64.9 TWh for the same periods in 2017, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations, and other grid-connected renewable resources. Baseload generation supply surplus in Ontario has been lower in 2018 compared to 2017, resulting in total forgone hydroelectric electricity generation for OPG of 1.2 TWh and 2.0 TWh due to SBG conditions in the three and six month periods ended June 30, 2018, respectively, compared to 2.6 TWh and 3.4 TWh during the same periods in 2017. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 1.1 TWh and 1.9 TWh in the three and six month periods ended June 30, 2018, respectively, compared to 2.2 TWh and 3.0 TWh during the same periods in 2017. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

### Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The new regulated prices for electricity generated from these segments approved by the OEB in its December 2017 decision and March 2018 payment amounts order, effective June 1, 2017, can be found in the section, *Core Business, Strategy, and Outlook* under the heading, *Financial Strength – Increasing Revenue, Reducing Costs and Achieving Appropriate Return* and are further discussed in OPG's 2018 First Quarter MD&A in the section, *Highlights* under the heading, *Recent Developments – OEB's Payment Amounts Order on OPG's Application for New Regulated Prices*.

The average sales price for the Regulated – Nuclear Generation segment was 7.9 and 7.5 cents per kilowatt hour (¢/kWh) during the three and six month periods ended June 30, 2018, respectively, compared to 5.7 ¢/kWh and 5.8 ¢/kWh during the same periods in 2017. The increase in the average sales price primarily reflected the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order. The increase in the average sales price during the six months ended June 30, 2018 was partially offset by a partial reversal of the regulatory asset for the June 1, 2017 to December 31, 2017 interim period revenue shortfall recorded in the fourth quarter of 2017 to reflect management's best estimate of the impact of the OEB's December 2017 decision, based on OPG's submission of a draft payment amounts order to the OEB in January 2018. The partial reversal was recorded in the first quarter of 2018 to reflect the issuance of the final payment amounts order in March 2018, which made certain adjustments to OPG's draft payment amounts order. These adjustments did not have a material impact on the results of operations for the six months ended June 30, 2018, as the revenue and income impact of the partial reversal of the interim period revenue shortfall regulatory asset was largely offset by the reversal of the regulatory liability for the Rate Smoothing Deferral Account recorded in the fourth quarter of 2017 based on the draft payment amounts order. Amounts deferred under rate smoothing are not included in the calculation of the average sales price until the period they are settled with ratepayers.

The average sales price for the Regulated – Hydroelectric segment was 4.2 ¢/kWh during the three and six month periods ended June 30, 2018, compared to 4.0 ¢/kWh and 4.1 ¢/kWh during the same periods in 2017. The higher average sales price in 2018 was mainly due to the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order.

### Cash Flow from Operations

Cash flow provided by operating activities was $413 million and $639 million for the three and six month periods ended June 30, 2018, respectively, compared to $89 million and $257 million for the same periods in 2017. The increase in cash flow provided by operating activities was mainly due to higher cash receipts from generation revenue reflecting the impact of the new regulated prices implemented following the issuance of the OEB's March 2018 payment amounts order, partially offset by the impact of lower electricity generation. The increase in cash flow provided by operating activities was also due to higher cash receipts from non-generation revenue and lower cash payments for income tax instalments.

### Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for the twelve months ended June 30, 2018 was 9.7 percent, compared to 7.6 percent for the twelve months ended December 31, 2017. The increase in ROE Excluding AOCI was primarily due to higher net income attributable to the Shareholder as a result of increased revenue reflecting the impact of the new regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and the gain on the sale of the former Lakeview GS site recorded in the second quarter of 2018. ROE Excluding AOCI for the twelve months ended December 31, 2017 reflected the gain on the sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017. The gains on the sale of the former Lakeview GS site and the sale of the head office premises and associated parking facility, including the effect of the associated special dividend authorized and paid in March 2018, together with the income tax effects of these transactions, contributed approximately 2.3 percent to ROE Excluding AOCI for the twelve months ended June 30, 2018 and approximately 2.5 percent for the twelve months ended December 31, 2017, as applicable.

### Enterprise Total Generating Cost per Megawatt Hour

The Enterprise TGC per megawatt hour (MWh) was $55.78 and $52.71 for the three and six month periods ended June 30, 2018, respectively, compared to $48.72 and $48.35 for the same periods in 2017. The increase in Enterprise TGC per MWh in 2018 was mainly due to the favourable impact of higher water flows on the SBG-adjusted hydroelectric electricity generation in 2017.

### Nuclear Total Generating Cost per Megawatt Hour

The Nuclear TGC per MWh was $86.03 and $77.74 for the three and six month periods ended June 30, 2018, respectively, compared to $76.87 and $73.24 for the same periods in 2017. The increase in Nuclear TGC per MWh was expected and primarily due to the lower nuclear electricity generation as a result of a higher number of planned outage days at the Pickering GS and the higher OM&A expenses associated with this increase in outage activity.

### Hydroelectric Total Generating Cost per Megawatt Hour

The Hydroelectric TGC per MWh was $23.81 and $22.16 for the three and six month periods ended June 30, 2018, respectively, compared to $19.83 and $19.81 for the same periods in 2017. The increase in Hydroelectric TGC per MWh was primarily due to the favourable impact of higher water flows on the SBG-adjusted hydroelectric electricity generation in 2017.

ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP, and should not be considered alternative measures to net income or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

## CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements*, at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities to the benefit of the Shareholder.

The following sections provide an update to OPG's disclosures in the 2017 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2017 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

### Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

The status updates for OPG's electricity generation portfolio as of June 30, 2018 are summarized below:

- In April 2018, the Ontario Chamber of Commerce released an economic impact study, which found that continued operation of the Pickering GS to 2024 will provide over 7,500 full-time equivalent jobs from direct employment at the station, indirect employment at suppliers, and induced spending from wages earned by individuals across all industries, in addition to providing Ontario with a clean, reliable source of baseload electricity. On June 21, 2018, the newly elected Premier of Ontario visited the Pickering GS and confirmed the Province's commitment to the continued operation of the station to 2024.
- OPG continues to invest prudently in the rehabilitation, overhaul and upgrades of its existing hydroelectric facilities. During the second quarter of 2018, OPG completed the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS and commenced execution of the automatic sluicegates system replacement at the Whitedog Falls GS. Work continuing on other projects includes the overhaul and upgrade of Unit 2 of the Little Long GS and the overhaul and upgrade of Unit 2 of the DeCew Falls 2 GS.

As part of the process to decommission the Lambton GS, a contract for the removal of the powerhouse and associated structures was issued in July 2018. Demolition activities continue for the powerhouse and associated structures of the Nanticoke GS. The costs of the decommissioning activities are charged to a previously established decommissioning provision.

Environmental Performance

In February 2018 and June 2018, the CNSC released sampling results from its 2017 independent environmental monitoring program, which confirmed that the public and environment around the Pickering GS and the Darlington GS are protected and that there are no expected health impacts. Samples were collected in publicly accessible areas outside the respective site perimeters and included air, water, soil, and vegetation. Samples of food were also taken from local farms.

Effective July 3, 2018, the Government of Ontario revoked the *Cap and Trade Program Regulation* which had been in effect since July 1, 2016. The cap and trade program was a market mechanism that put a price on carbon in Ontario. The revocation of the program is not expected to have a material financial impact on the Company and will result in lower fuel costs for some of OPG's owned and co-owned generating facilities. Fuel costs for these stations are generally recovered from the electricity market.

Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2017 annual MD&A.

## Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. The status updates for OPG's major projects as of June 30, 2018 are outlined below.

| Project | Capital expenditures | | Approved budget | Expected in-service date | Current status |
|---|---|---|---|---|---|
| *(millions of dollars)* | Year-to-date | Life-to-date | | | |
| Darlington Refurbishment | 488 | 4,922 | 12,800 [1] | First unit - 2020<br>Last unit - 2026 | The reassembly of Unit 2 reactor components commenced in July 2018 and is in progress. Planning activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and to the $12.8 billion budget. |
| Ranney Falls Hydroelectric GS | 16 | 44 | 77 | 2019 | Construction continues with concrete placement of the expanded forebay, powerhouse and spillway. Sectional gates and head gates installation, substation construction, and turbine and generator unit fabrication are in progress. The project's expected in-service date is in the fourth quarter of 2019. The project is tracking on schedule and on budget. |
| Nanticoke Solar Facility | 17 | 20 | 107 | 2019 | Construction commenced during the second quarter of 2018 with the installation of solar module supports at the site. The solar modules and inverter equipment are being delivered in the second half of 2018. The facility is expected to be completed in the first quarter of 2019. The project is tracking on schedule and on budget. |
| Deep Geologic Repository (DGR) for Low and Intermediate Level Radioactive Waste (L&ILW) | 4 [2] | 208 [2] | | | In August 2017, as part of the Environmental Assessment approval process, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the SON's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction. |

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS, including the costs of the pre-requisite projects in support of the execution phase of the refurbishment. Project costs that do not meet capitalization criteria are charged to OM&A expenses in the period incurred.

[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the prerequisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

OPG commenced the refurbishment of the first unit, Unit 2, in October 2016. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in the first half of 2017, signifying the completion of the first major segment of the Unit 2 refurbishment.

The second major segment included the disassembly and removal of the existing reactor components. In early May 2018, OPG completed the removal of the reactor components, which included end fittings, pressure tubes and calandria tubes, signifying the completion of the second major segment of the Unit 2 refurbishment.

The Unit 2 refurbishment is now in the third major segment, the installation and reassembly of reactor components, including new feeder tubes and fuel channel assemblies. In June 2018, OPG completed inspections and cleaning on the reactor face in preparation for the reassembly of the reactor components, and in July 2018, commenced the reassembly of Unit 2. The third segment is progressing as planned, with the new calandria tube installation series currently in progress. Construction activities on the Heavy Water Storage and Drum Handling Facility are continuing.

The planning and prerequisite activities for the refurbishment of the second unit, Unit 3, continues to progress in accordance with the overall project schedule, incorporating experience learned to date from the Unit 2 refurbishment. OPG is continuing to enter into commitments to procure major components that require long lead times. The Unit 3 refurbishment execution is expected to commence upon the return to service of Unit 2. As of June 30, 2018, $169 million has been invested in planning and prerequisite activities related to the Unit 3 refurbishment.

The Darlington Refurbishment project continues to track on schedule and to the $12.8 billion budget.

## Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking continued efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices.

The OEB's December 2017 decision and March 2018 payment amounts order on OPG's 2017-2021 rate application establishing new regulated prices effective June 1, 2017 provide substantial price certainty for the regulated business up to 2021. While the OEB set costs for determining the new regulated prices below OPG's forecasted levels, including through the use of stretch factors under incentive ratemaking, the new regulated prices will result in a substantial increase in revenue and net income compared to the previously approved prices.

The regulated prices authorized by the OEB's December 2017 decision and March 2018 payment amounts order are as follows:

| *($/MWh)* | **2017 June 1 to December 31** | **2018** | **2019** | **2020** | **2021** |
|---|---|---|---|---|---|
| **Regulated – Nuclear Generation** | | | | | |
| Base regulated price | 77.96 | 78.64 | 77.00 | 85.00 | 89.70 |
| Interim period shortfall rider [1] | - | 2.89 | 7.71 | 5.64 | - |
| Variance and deferral account rate rider [2] | - | 1.05 | 2.79 | 2.04 | - |
| | 77.96 | 82.58 | 87.50 | 92.68 | 89.70 |
| **Regulated – Hydroelectric** | | | | | |
| Base regulated price [3] | 41.67 | 42.05 | n/a | n/a | n/a |
| Interim period shortfall rider [1] | - | 0.13 | 0.35 | 0.24 | - |
| Variance and deferral account rate rider [2] | - | 0.52 | 1.44 | 1.01 | - |
| | 41.67 | 42.70 | n/a | n/a | n/a |

[1] As part of the payment amounts order process, the OEB authorized separate rate riders to allow for the recovery of the revenue shortfall between the new base regulated prices and the previously approved base regulated prices that OPG continued to receive during the interim period between June 1, 2017 and February 28, 2018, over the March 1, 2018 to December 31, 2020 period. The revenue shortfall was recorded as a regulatory asset in the fourth quarter of 2017 and the first quarter of 2018.

[2] Variance and deferral account riders reflect OEB's approval to recover the balances recorded in regulatory accounts as at December 31, 2015 that were requested for disposition in OPG's 2017-2021 rate application.

[3] Base regulated prices for the regulated hydroelectric facilities for the 2019-2021 period will be determined annually through a formulaic adjustment using the OEB-approved incentive regulation formula and OEB-published inflation indices.

Consistent with the OEB's December 2017 decision, in the third quarter of 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash to Accrual Differential Deferral Account balance as at December 31, 2017, as well as balances accumulated between January 1, 2016 and December 31, 2017 in other variance and deferral accounts. OPG plans to request the disposition of these balances through incremental nuclear and regulated hydroelectric rate riders beginning in 2019. If approved by the OEB, these rate riders will contribute to improved cash flow from operating activities but will not have a material impact on net income, as the revenue from the recovery of the regulatory balances will be largely offset by amortization expense related to the regulatory assets and regulatory liabilities for these balances. In this application, OPG will also apply for the annual formulaic adjustment to set the 2019 base regulated price for the regulated hydroelectric facilities.

To further improve the financial strength of the regulated operations, OPG continues to focus on optimizing operational performance and outage plans across the generating fleet and to pursue further efficiency improvements in the Company's cost structure and operating model. This includes continuing to progress the multi-year OPG25 initiative, which involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering GS commercial operation in 2024.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure of 45 percent equity and 55 percent debt maintained by the OEB's December 2017 decision. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

In April 2018, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2018, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG believes in building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with Indigenous communities. OPG seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of Indigenous communities. In June 2018, OPG held an unveiling event for a new Indigenous cultural and historical display at the Darlington Energy Complex. The display was designed in partnership with representatives from Scugog Island, Curve Lake, Hiawatha and Alderville First Nations, and will help to inform the public and OPG employees about the history and culture of the Mississauga people.

OPG remains focused on identifying ways to increase the Indigenous representation in OPG's workforce, including through the launch of the Indigenous Opportunities in Nuclear (ION) program in the first quarter of 2018, using the Darlington Refurbishment project as a catalyst. During the first half of 2018, skilled candidates from Indigenous communities have been placed in OPG's nuclear operations through the ION program with the assistance of Kagita Mikam, an Aboriginal Employment and Training agency based at Tyendinaga within Mohawks of the Bay of Quinte territory, as a strategic partner.

In June 2018, Corporate Knights released the annual Best 50 Corporate Citizens in Canada list of which OPG placed 11$^{th}$ on the list, an improvement over the Company's previous year's placement. The annual corporate rankings were based on energy efficiency and reducing greenhouse gas emissions, with an emphasis on transparency and continuity in order to recognize companies leading in sustainability.

## Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of the Company's applications for regulated prices to the OEB.

In 2018, the full-year effect of the new regulated prices established by the OEB's December 2017 decision and March 2018 payment amounts order will contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results. An improvement in cash flow from operating activities during the remainder of 2018, compared to 2017, is also expected as a result of the new regulated prices, including from the collection of the interim period revenue shortfall for the June 1, 2017 to February 1, 2018 period.

Several regulatory accounts will continue to reduce the relative variability of the Company's net income and ROE Excluding AOCI. Among others, these accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on continuing to strengthen the overall reliability and predictability of the

fleet. Taking into account outage activity planned at the nuclear generating stations in the second half of the year, OPG expects a year-over-year increase in earnings from the Regulated – Nuclear segment in 2018.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures, nuclear outage profile and water flows may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds established under the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, which are reported in the Regulated – Nuclear Waste Management segment. Variations in rates of return for the funds based on financial market conditions, including changes in the Ontario consumer price index (CPI) that affect earnings on the portion of the Used Fuel Segregated Fund guaranteed by the Province, can be volatile and cause fluctuations in the Company's income in the near term. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and during periods when the funds are in a fully funded or overfunded position. As at June 30, 2018, the Decommissioning Segregated Fund was overfunded by approximately 28 percent, and the Used Fuel Segregated Fund was marginally overfunded, by approximately one percent, based on the current ONFA reference plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results include the earnings and operating cash flow from the Fair Hydro Trust segment, primarily related to interest income from the Fair Hydro Trust (the Trust). OPG's involvement as the Financial Services Manager under the Fair Hydro Act puts downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through issuances of Class A shares to partially fund OPG's purchases of the Trust's subordinated debt, partially offset by the impact of incremental earnings from the Trust.

## ENVIRONMENTAL, SOCIAL, GOVERNANCE, AND SUSTAINABILITY

OPG is in the process of developing its Environmental, Social, Governance (ESG), and Sustainability framework to best reflect and disclose information that is meaningful to stakeholders. OPG plans to structure its ESG and Sustainability framework around four core themes:

- **Metrics and targets** to assess and manage relevant climate-related risks and opportunities;
- **Risk management** processes to identify, assess and manage climate-related risks and opportunities;
- **Strategy** for incorporating climate change impacts into business planning and decision-making; and
- **Governance** for integrating the climate change strategy in the business.

In developing its ESG and Sustainability framework, OPG expects to leverage industry-specific and other emerging guidance on best practices related to ESG and Sustainability reporting and continues to monitor the Canadian

Securities Administrators' project to review the disclosures of risks and financial impacts associated with climate change.

*Metrics and Targets*

The annual sustainability report is the Company's platform for communicating the value OPG places on sustainability, the Company's approach to managing its impacts, and recent performance results and trends. The Company tracks, measures, evaluates and discloses its goals, targets and performance results for the priority sustainability topics, which include greenhouse gas emissions and climate change, nuclear emissions, water management and flows, and environmental compliance and spills.

OPG's priority sustainability topics were formally identified through an assessment that reviewed and ranked the environmental, social and economic aspects of OPG's activities based on the views of external and internal stakeholders. These assessments will be incorporated into the evaluation of climate change risk areas and associated climate change scenario analyses.

*Risk Management*

OPG has held climate change adaptation workshops within the Company to identify potential impacts on the Company's operational systems and processes resulting from changes in various climate parameters. Climate parameters considered included changes in average temperature and precipitation, variability of weather patterns and expected changes in extreme weather events that could affect the Company. The next steps include identifying the data required to support a quantitative evaluation of potential climate change impacts and implementing measures to integrate climate-related risk considerations into business decisions. This process will leverage OPG's collaboration with the Ouranos Consortium on Regional Climatology and Adaptation to Climate Change and data from the Pacific Climate Impacts Consortium to ensure expert-generated climate projections are used in the Company's assessments of climate-related impacts.

OPG has worked to develop action plans in response to climate change related catastrophic events. In response to the 2011 Fukushima Daiichi incident in Japan, OPG completed a systematic review and verification of defences against external hazards at OPG-operated nuclear generating stations. The review showed that the nuclear safety systems and multiple back-up power systems in place at the stations are effective, the current design of the stations is strong, and the stations are able to withstand extreme external events. In addition, OPG's Fukushima Implementation Plan included a number of key safety enhancements for providing additional back-up capability to increase OPG's flexibility to respond to unexpected and highly unlikely external events that can impact either a single unit or multiple nuclear units at the same time. CNSC staff concluded that OPG had strengthened reactor defence and enhanced its emergency response at both the Darlington GS and the Pickering GS in response to the lessons learned from the Fukushima Daiichi incident.

*Strategy*

In 2014, OPG ended coal-fired generation, which marked the end of coal-fired generation in Ontario. With the growing need for comprehensive planning of business priorities within the context of climate change, OPG is developing a climate change management plan that will provide an integrated view of the relevant activities and initiatives across the Company. This plan will guide the integration of climate change impacts into business planning and decision-making.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province, as a key action to reduce greenhouse gas emissions in Ontario. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

As discussed in the section, *Highlights* under the heading, *Recent Developments – Green Bond Offering*, in line with the Company's climate change strategy, in June 2018, OPG issued an inaugural green bond offering under OPG's existing Medium Term Note Program. Over two thirds of the amount issued was acquired by investors that are signatories to the United Nations Principles for Responsible Investment of which some investors had specific green mandates.

*Governance*

In 2018, OPG established an ESG, and Sustainability steering committee consisting of a diverse group of representatives from various disciplines within the Company. The committee is responsible for evaluating the potential impact of emerging environmental issues on the Company, overseeing the development of a formal climate change strategy, assessing and monitoring the evolution of climate-related risks, and developing associated financial reporting disclosures.

OPG has maintained an ISO 14001-registered Environmental Management System (EMS) since 1999. In May 2018, OPG successfully registered the EMS to the new ISO 14001:2015 version of the standard.

## DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

### Regulated – Nuclear Generation Segment

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** |
| Revenue | **734** | 609 | **1,614** | 1,261 |
| Fuel expense | **62** | 68 | **135** | 136 |
| Gross margin | **672** | 541 | **1,479** | 1,125 |
| Operations, maintenance and administration | **620** | 593 | **1,224** | 1,182 |
| Depreciation and amortization | **130** | 110 | **251** | 217 |
| Property taxes | **6** | 7 | **13** | 13 |
| Loss before interest and income taxes | **(84)** | (169) | **(9)** | (287) |

Income before interest and income taxes from the segment increased by $85 million and $278 million for the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017. The increase in earnings was primarily due to an increase in revenue of approximately $170 million and $375 million for the three and six month periods ended June 30, 2018, respectively, as a result of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order. This increase was partially offset by a decrease in revenue of $45 million and $20 million for the three and six month periods ended June 30, 2018, respectively, due to lower electricity generation from the segment, compared to the same periods in 2017.

The increase in OM&A expenses of $27 million and $42 million in the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, also partially offset the increase in segment earnings. The increase in OM&A expenses was primarily due to services and materials costs associated with a higher number of planned outage days at the Pickering GS, which reflected a higher concentration of the year's planned outage days at the station in the second quarter of 2018, compared to the same period in 2017, as part of the station's cyclical maintenance schedule.

Higher depreciation and amortization expenses of $10 million and $21 million, excluding amortization expense related to the recovery of regulatory account balances, in the three and six month periods ended June 30, 2018, respectively, compared to the same periods in 2017, were mainly due to increased depreciation from new assets in service. The

increase in amortization expense related to regulatory account balances was largely offset by an increase revenue from the nuclear rate rider authorized in the OEB's December 2017 decision and March 2018 payment amounts order for the recovery of these balances.

In the fourth quarter of 2017, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 to December 31, 2022 for Units 1 and 4 and to December 31, 2024 for Units 5 to 8, and recorded a corresponding change in the nuclear asset retirement obligation and associated asset retirement costs capitalized as part of the carrying value of property, plant and equipment, effective December 31, 2017. The decrease in depreciation expense associated with this change in the end-of-life assumptions during the three and six month periods ended June 30, 2018 was offset by the impact of regulatory accounts, including the new Impact Resulting from Changes to Pickering Station End-of-Life Dates Deferral Account authorized by the OEB on a final basis in a May 31, 2018 decision and order on OPG's application for such an account. The OEB had previously issued a decision in January 2018 establishing the proposed account on an interim basis to allow OPG to record amounts in the account as of January 1, 2018. The application was filed pursuant to requirements set out in prior OEB decisions and orders.

The Unit Capability Factors for the Darlington GS and Pickering GS were as follows:

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Unit Capability Factor *(%)* [1] | | | | |
| Darlington GS | **67.4** | 64.6 | **81.9** | 74.9 |
| Pickering GS | **71.3** | 84.2 | **72.9** | 81.4 |

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased during the second quarter of 2018, compared to the same quarter in 2017, primarily due to fewer unplanned outage days at the station. The Unit Capability Factor at the Darlington GS increased during the six months ended June 30, 2018, compared to the same period in 2017, primarily due to fewer planned outage days at the station in the first quarter of 2018.

The decrease in the Unit Capability Factor at the Pickering GS during the three and six month periods ended June 30, 2018, compared to the same periods in 2017, was expected and primarily due to a higher number of planned outage days in the station's cyclical maintenance schedule in the first half of 2018.

### Regulated – Nuclear Waste Management Segment

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** |
| Revenue | **32** | 30 | **65** | 57 |
| Operations, maintenance and administration | **32** | 32 | **65** | 61 |
| Accretion on nuclear fixed asset removal and nuclear waste management liabilities | **244** | 232 | **487** | 466 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(212)** | (194) | **(422)** | (383) |
| Loss before interest and income taxes | **(32)** | (40) | **(65)** | (87) |

The segment loss before interest and income taxes was $32 million and $65 million during the three and six month periods ended June 30, 2018, respectively, representing an increase in earnings of $8 million and $22 million compared to the same periods in 2017. The improvement in segment earnings was primarily a result of higher

earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The increase in earnings from the Nuclear Segregated Funds resulted from a higher amount of fund earnings deferred in regulatory accounts in the first half of 2017, due to fund earnings not included in the nuclear base regulated price in effect prior to the OEB's December 2017 decision, and the growth rate in the present value of the underlying funding liabilities per the current approved ONFA reference plan in effect since January 1, 2017. As the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position since the beginning of 2017, they were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. When both funds are in an overfunded position, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan. Further details on the accounting for the Nuclear Segregated Funds can be found in OPG's 2017 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The increase in accretion expense on the Nuclear Liabilities was mainly due to a higher amount of accretion expense deferred in regulatory accounts in the first half of 2017, due to costs not included in the nuclear base regulated price in effect prior to the OEB's December 2017 decision.

**Regulated – Hydroelectric Segment**

| *(millions of dollars)* | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Revenue [1] | **390** | 379 | **746** | 742 |
| Fuel expense | **90** | 97 | **155** | 170 |
| Gross margin | **300** | 282 | **591** | 572 |
| Operations, maintenance and administration | **82** | 75 | **162** | 151 |
| Depreciation and amortization | **40** | 35 | **76** | 69 |
| Income before other losses, interest and income taxes | **178** | 172 | **353** | 352 |
| Other losses | **-** | - | **4** | - |
| Income before interest and income taxes | **178** | 172 | **349** | 352 |

[1] During the three and six month periods ended June 30, 2018, the Regulated – Hydroelectric segment revenue included incentive payment reductions of $1 million and nil, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and six month periods ended June 30, 2017 – incentive payment reductions of $3 million and incentive payments of $5 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

Income before interest and income taxes from the segment increased by $6 million during the second quarter of 2018, compared to the same quarter in 2017. The increase in earnings was primarily due to an increase in revenue of approximately $8 million to reflect the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order, and lower hydroelectric incentive mechanism payment reductions. These factors were partially offset by higher OM&A expenses in the second quarter of 2018.

The decrease in segment income before interest and income taxes of $3 million during the six months ended June 30, 2018, compared to the same period in 2017, was mainly due to higher OM&A expenses and lower hydroelectric incentive mechanism payments. The decrease in earnings from the segment was partially offset by an increase in revenue of approximately $13 million to reflect the impact of the new base regulated prices approved by the OEB in its December 2017 decision and March 2018 payment amounts order.

The higher OM&A expenses for the three and six month periods ended June 30, 2018, compared to the same periods in 2017, were mainly due to higher hydroelectric project expenses and increased maintenance work programs.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Hydroelectric Availability *(%)* | **88.6** | 90.1 | **87.9** | 89.8 |

The Hydroelectric Availability decreased in the three and six month periods ended June 30, 2018, compared to the same periods in 2017, primarily due to a higher number of unplanned outage days at the eastern and northeastern Ontario regions' regulated hydroelectric stations.

**Contracted Generation Portfolio Segment**

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** |
| Revenue | **149** | 147 | **298** | 290 |
| Fuel expense | **14** | 13 | **31** | 27 |
| Gross margin | **135** | 134 | **267** | 263 |
| Operations, maintenance and administration | **43** | 40 | **84** | 79 |
| Depreciation and amortization | **19** | 20 | **39** | 39 |
| Accretion on fixed asset removal liabilities | **2** | 2 | **4** | 4 |
| Property taxes | **3** | 3 | **4** | 5 |
| Income from investments subject to significant influence | **(10)** | (8) | **(20)** | (18) |
| Income before interest and income taxes | **78** | 77 | **156** | 154 |

Income before interest and income taxes from the segment for the three and six month periods ended June 30, 2018 was comparable to the same periods in 2017. The increase in gross margin during the six months ended June 30, 2018, compared to the same period in 2017, was primarily due to revenue generated from the Peter Sutherland Sr. hydroelectric GS that was placed in-service at the end of the first quarter of 2017. The increase in OM&A expenses during the six months ended June 30, 2018, compared to the same period in 2017, reflected higher station expenditures at the Lennox GS and the Atikokan GS.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Hydroelectric Availability *(%)* | **86.5** | 81.4 | **83.3** | 82.5 |
| Thermal EFOR *(%)* | **1.4** | 2.7 | **0.8** | 7.8 |

The Hydroelectric Availability increased during the three and six month periods ended June 30, 2018, compared to the same periods in 2017. The increase was primarily due to a lower number of unplanned outage days at the northeastern Ontario region's contracted hydroelectric stations.

The Thermal EFOR decreased during the three and six month periods ended June 30, 2018, compared to the same periods in 2017. The decrease was primarily due to a lower number of unplanned outage days at the Lennox GS.

## Fair Hydro Trust Segment

| *(millions of dollars)* | Three Months Ended June 30 2018 | 2017 | Six Months Ended June 30 2018 | 2017 |
|---|---|---|---|---|
| Earnings from Fair Hydro Trust | **8** | - | **12** | - |
| Income before interest and income taxes | **8** | - | **12** | - |

The Fair Hydro Trust was established in December 2017 as the financing entity contemplated by the Fair Hydro Act, for the purpose of acquiring Investment Interests from the IESO, being the irrevocable right to recover Global Adjustment costs deferred by the IESO under the Fair Hydro Act and associated financing and other costs. In order for the Trust to finance such acquisitions, it incurs senior debt from capital markets and subordinated debt from OPG. The Company consolidates the financial results of the Trust in accordance with US GAAP. Earnings from Fair Hydro Trust primarily comprise interest income, partially offset by interest costs on debt incurred by OPG to fund purchases of the Trust's subordinated debt.

In April 2018, the Trust purchased an Investment Interest from the IESO in the amount of $149 million.

Approximately $76 million of the purchase price was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining $73 million was funded through the following sources:

- the Province provided $66 million through equity injections in OPG in exchange for approximately 1.5 million non-voting Class A shares at a price of $43.74 per share; and
- OPG provided $7 million.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements.

## LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes, including investment in plants and technologies, funding to undertake major projects, funding long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, making payments under the OPEB plans, funding expenditures on the Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, servicing and repaying long-term debt, providing general working capital, and funding a portion of OPG's purchases of subordinated debt issued by the Fair Hydro Trust.

Changes in cash, cash equivalents and restricted cash for the three and six month periods ended June 30, 2018 and 2017 were as follows:

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** |
| Cash, cash equivalents and restricted cash, beginning of period | **328** | 220 | **234** | 186 |
| Cash flow provided by operating activities | **413** | 89 | **639** | 257 |
| Cash flow (used in) provided by investing activities | **(539)** | 112 | **(1,143)** | (301) |
| Cash flow provided by (used in) financing activities | **383** | (179) | **855** | 100 |
| Net increase in cash, cash equivalents and restricted cash | **257** | 22 | **351** | 56 |
| Cash, cash equivalents and restricted cash, end of period | **585** | 242 | **585** | 242 |

For a discussion of cash flow provided by operating activities, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

### Investing Activities

Cash flow used in investing activities during the second quarter of 2018 was $539 million, compared to cash flow provided by investing activities of $112 million for the same quarter in 2017. Cash flow used in investing activities during the six months ended June 30, 2018 was $1,143 million, compared to $301 million for the same period in 2017. The increase in cash flow used in investing activities for the three and six month periods ended June 30, 2018 was mainly due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 and the purchases of Investment Interests from the IESO by the Fair Hydro Trust in 2018. The increase in cash flow used in investing activities for the six months ended June 30, 2018 was partially offset by the receipt of proceeds from the sale of the former Lakeview GS site in March 2018.

### Financing Activities

In March and April 2018, OPG issued 4,627,343 and 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $66 million, respectively. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisitions of Investment Interests from the IESO during these periods.

During the first quarter of 2018, OPG issued a total of $600 million senior notes payable to OEFC maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent. During the second quarter of 2018, OPG issued $450 million senior notes under its Medium Term Notes Program, maturing in 2048. The effective and coupon interest rates on these notes were 3.92 percent and 3.84 percent, respectively. The notes were issued under OPG's Green Bond Framework to provide funding for eligible hydroelectric projects.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year revolving senior warehouse facility agreement expiring in December 2019. As at June 30, 2018, there were outstanding senior notes of $12 million under this credit facility. Approximately $76 million was issued under the credit facility in April 2018 to finance 51 percent of the Trust's funding requirement for the acquisition of Investment Interest from the IESO in April 2018.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust to provide a portion of the funding requirement for its first purchase of Investment Interest from the IESO in December 2017.

In April 2018, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility after the acquisition of Investment Interest in April 2018.

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2018, OPG renewed and extended the expiry date of both tranches from May 2022 to May 2023. There were no amounts outstanding under the bank credit facility as at June 30, 2018.

As at June 30, 2018, short-term debt outstanding was $114 million, representing external commercial paper outstanding under Lower Mattagami Energy Limited Partnership's commercial paper program.

As at June 30, 2018, long-term debt outstanding including the Fair Hydro Trust's senior debt reported on OPG's interim consolidated balance sheets was $7,370 million, with $288 million representing amounts due within one year. The balance included $1,400 million outstanding under OPG's $2,350 million general corporate credit facility agreement with the OEFC that expires on December 31, 2018. The Fair Hydro Trust's senior debt outstanding was $912 million as at June 30, 2018.

**BALANCE SHEET HIGHLIGHTS**

The following section provides other highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

| *(millions of dollars)* | As At June 30 2018 | As At December 31 2017 |
|---|---|---|
| **Property, plant and equipment – net** | **21,755** | 21,322 |
| The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense. | | |
| **Nuclear fixed asset removal and nuclear waste management funds** *(current and non-current portions)* | **17,098** | 16,724 |
| The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities. | | |
| **Regulatory assets and liabilities – net** *(current and non-current portions)* | **6,758** | 6,637 |
| The increase was primarily due to additions recorded in regulatory accounts pursuant to the OEB's decisions and orders, the recognition of the interim period revenue shortfall for January and February 2018, and an increase in the regulatory asset for deferred income taxes, partially offset by the decrease in the Pension and OPEB Regulatory Asset. | | |
| **Long-term debt** *(current and non-current portions)* | **7,345** | 6,319 |
| The increase was primarily due to the issuance of senior notes payable to the OEFC, the issuance of senior notes payable under the Company's Medium Term Note Program, and the issuance of senior notes payable by the Fair Hydro Trust. The increase was partially offset by debt repayments. | | |
| **Fixed asset removal and nuclear waste management liabilities** | **20,838** | 20,421 |
| The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities. | | |

**Off-Balance Sheet Arrangements**

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

## CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to OPG's audited consolidated financial statements as at and for the year ended December 31, 2017. A discussion of recent accounting pronouncements and changes in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and six month periods ended June 30, 2018. Disclosure regarding OPG's critical accounting policies is included in OPG's 2017 annual MD&A.

### Exemptive Relief for Reporting under US GAAP

In April 2018, OPG received an extension to its exemptive relief from the OSC requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than IFRS, without becoming a Securities and Exchange Commission registrant. This exemption replaces the exemptive relief received by OPG from the OSC in February 2014. The exemption will terminate on the earliest of the following:

- January 1, 2024;
- the financial year that commences after OPG ceases to have activities subject to rate regulation; and
- the effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

The IASB's current standard-setting project related to entities with rate-regulated activities is ongoing.

## RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2017 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

### Risks to Maintaining Financial Strength

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

| | 2018 [1] | 2019 | 2020 |
|---|---|---|---|
| Estimated fuel requirements hedged [2] | 78% | 75% | 76% |

[1] Based on actual fuel requirements hedged for the six months ended June 30, 2018 and forecast for the remainder of the year.

[2] Represents the approximate portion of MWh of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at June 30, 2018, OPG had no foreign exchange contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the second quarter of 2018, the VaR utilization ranged between nil and $0.1 million.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to energy markets transactions as at June 30, 2018 was $387 million, including $379 million to the IESO. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $8 million remaining exposure as at June 30, 2018, over 95 percent was with investment grade counterparties. Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Government Legislation and Regulation Changes

The Ontario provincial election took place in June 2018 and resulted in a change in governing party. There may be significant legislative and regulation changes enacted by the new provincial government that could impact Ontario's electricity industry. The Company has actively engaged with the new provincial government to brief them on the role of OPG in Ontario's electricity market and the Company's contribution to the Shareholder.

## RELATED PARTY TRANSACTIONS

Given that the Province owns all of the outstanding common shares and Class A shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One Limited (Hydro One), the IESO, and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As a wholly owned government business enterprise of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

| | Three Months Ended June 30 | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| *(millions of dollars)* | **Income** | **Expense** | **Income** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **2** | **-** | 1 | - |
| Services | **-** | **2** | - | - |
| Dividends | **2** | **-** | 2 | - |
| Province of Ontario | | | | |
| Change in Decommissioning Segregated Fund amount due to Province [1] | **-** | **104** | - | 45 |
| Change in Used Fuel Segregated Fund amount due to Province [1] | **-** | **141** | - | 39 |
| Hydroelectric gross revenue charge | **-** | **28** | - | 29 |
| ONFA guarantee fee | **-** | **-** | - | 2 |
| Other | **-** | **-** | - | 1 |
| OEFC | | | | |
| Hydroelectric gross revenue charge | **-** | **57** | - | 56 |
| Interest expense on long-term notes | **-** | **37** | - | 41 |
| Income taxes | **-** | **41** | - | 97 |
| IESO | | | | |
| Electricity related revenue | **1,162** | **-** | 1,028 | - |
| Fair Hydro Trust | **17** | **-** | - | - |
| | **1,183** | **410** | 1,031 | 310 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at June 30, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,683 million and $4,462 million, respectively.

| *(millions of dollars)* | Six Months Ended June 30 | | | |
|---|---|---|---|---|
| | 2018 | | 2017 | |
| | **Income** | **Expense** | **Income** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **6** | **-** | 5 | - |
| Services | **-** | **7** | 1 | 5 |
| Dividends | **4** | **-** | 4 | - |
| Province of Ontario | | | | |
| Change in Decommissioning Segregated Fund amount due to Province [1] | **-** | **102** | - | 208 |
| Change in Used Fuel Segregated Fund amount due to Province [1] | **-** | **120** | - | 256 |
| Hydroelectric gross revenue charge | **-** | **56** | - | 57 |
| ONFA guarantee fee | **-** | **-** | - | 4 |
| Other | **-** | **-** | | 1 |
| OEFC | | | | |
| Hydroelectric gross revenue charge | **-** | **95** | - | 94 |
| Interest expense on long-term notes | **-** | **74** | - | 82 |
| Income taxes | **-** | **94** | - | 109 |
| IESO | | | | |
| Electricity related revenue | **2,394** | **-** | 2,095 | - |
| Fair Hydro Trust | **28** | **-** | - | - |
| | **2,432** | **548** | 2,105 | 816 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at June 30, 2018 and December 31, 2017, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,683 million and $4,462 million, respectively.

The receivable, equity securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| *(millions of dollars)* | **June 30 2018** | **December 31 2017** |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO - Electricity related receivables | **379** | 354 |
| IESO - Fair Hydro Trust [1] | **8** | 7 |
| OEFC | **9** | - |
| PEC | **4** | 4 |
| Province of Ontario | **5** | 3 |
| Financing receivables | | |
| IESO - Fair Hydro Trust | **1,788** | 1,179 |
| Equity securities | | |
| Hydro One shares | **151** | 188 |
| Accounts payable and accrued charges | | |
| Hydro One | **-** | 1 |
| OEFC | **53** | 52 |
| Province of Ontario | **6** | 9 |
| IESO - Electricity related payables | **4** | 11 |
| IESO - Fair Hydro Trust | **16** | 3 |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,470** | 3,195 |

[1] Balance consists of unbilled cost recovery revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at June 30, 2018, the Nuclear Segregated Funds held $1,373 million of Province of Ontario bonds (December 31, 2017 – $1,502 million) and $8 million of Province of Ontario treasury bills (December 31, 2017 − $9 million). As at June 30, 2018, the registered pension fund did not hold Province of Ontario bonds or treasury bills (December 31, 2017 − $1 million of Province of Ontario treasury bills). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In March and April 2018, the Fair Hydro Trust purchased Investment Interests from the IESO for an exchange amount of $460 million and $149 million, respectively, which have been classified as financing receivables on OPG's unaudited interim consolidated balance sheets. The transactions were settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, residential, farm, small businesses and other eligible customers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust and principal on debt. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivables. The three-month overlap in 2021 is intended to cover the billing and collections lag from the introduction of the Clean Energy Adjustment.

As at June 30, 2018, OPG's unaudited interim consolidated balance sheets included approximately $8 million of unbilled cost recovery revenue from the IESO (December 31, 2017 – $7 million), primarily for OPG's general fee for 2017 as the Financial Services Manager under the Fair Hydro Act relating to incurred third-party and certain direct labour costs. In July 2018, the OEB approved OPG's proposed general fee for 2017 of approximately $6 million. The

OEB also approved OPG's proposed benchmark interest rates for use in calculating a portion of the Company's fees for providing financial management and ongoing administration services to the Trust for 2018 and for the first quarter of 2019.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interests to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Fair Hydro Act is invalid or unconstitutional.

## INTERNAL CONTROL OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal control over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

## QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

| *(millions of dollars – except where noted)* | **June 30 2018** | **March 31 2018** | **December 31 2017** | **September 30 2017** |
|---|---|---|---|---|
| Revenue | **1,282** | 1,407 | 1,619 | 1,217 |
| Net income | **126** | 539 | 366 | 140 |
| Less: Net income attributable to non-controlling interest | **5** | 4 | 4 | 9 |
| Net income attributable to the Shareholder | **121** | 535 | 362 | 131 |
| **Earnings per share, attributable to the Shareholder *(dollars)*** | **$0.44** | $1.99 | $1.41 | $0.51 |

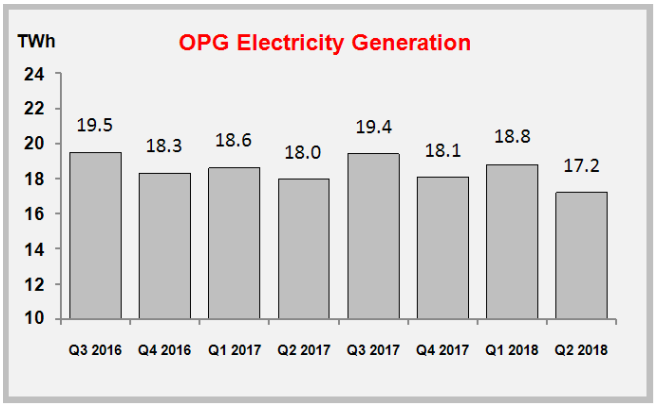
| *(millions of dollars – except where noted)* | **June 30 2017** | **March 31 2017** | **December 31 2016** | **September 30 2016** |
|---|---|---|---|---|
| Revenue | 1,146 | 1,176 | 1,388 | 1,400 |
| Net income (loss) | 307 | 68 | (8) | 198 |
| Less: Net income attribute to the non-controlling interest | 4 | 4 | 5 | 4 |
| Net income (loss) attributable to the Shareholder | 303 | 64 | (13) | 194 |
| **Earnings (Loss) per share, attributable to the Shareholder *(dollars)*** | $1.18 | $0.25 | ($0.05) | $0.76 |

## Trends

OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by the OEB-authorized regulatory accounts.

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year. The Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is continuing, has reduced electricity generation starting in the fourth quarter of 2016.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status, as discussed in the 2017 annual M&DA in the section, *Risk Management* under the heading, *Nuclear Liabilities and Nuclear Segregated Funds*.



## SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP, and therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

| | Twelve Months Ended | |
|---|---|---|
| *(millions of dollars – except where noted)* | **June 30 2018** | **December 31 2017** |
| ROE Excluding AOCI | | |
| Net income attributable to the Shareholder | **1,149** | 860 |
| Divided by: Average equity attributable to the Shareholder, excluding AOCI | **11,848** | 11,351 |
| **ROE Excluding AOCI *(percent)*** | **9.7** | 7.6 |

(2) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, the Fair Hydro Trust segment, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

| | **Three Months Ended June 30** | | **Six Months Ended June 30** | |
|---|---|---|---|---|
| *(millions of dollars – except where noted)* | **2018** | **2017** | **2018** | **2017** |
| Enterprise TGC | | | | |
| Total OM&A expenses | **743** | 711 | **1,465** | 1,419 |
| Total fuel expense | **166** | 178 | **321** | 333 |
| Total capital expenditures | **396** | 451 | **755** | 859 |
| Less: Darlington Refurbishment capital and OM&A costs | **(258)** | (306) | **(517)** | (615) |
| Less: Other generation development project capital and OM&A costs | **(28)** | (19) | **(45)** | (36) |
| Add (Less): OM&A and fuel expenses deferred in (refundable through) regulatory variance and deferral accounts | **2** | (12) | **28** | (23) |
| Less: Nuclear fuel expense for non OPG-operated stations | **(17)** | (16) | **(32)** | (29) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **15** | 23 | **21** | 34 |
| Less: OM&A expenses ancillary to electricity generation business | **(3)** | (4) | **(7)** | (9) |
| Other adjustments | **(1)** | (2) | **(1)** | (4) |
| | **1,015** | 1,004 | **1,988** | 1,929 |
| Adjusted electricity generation *(TWh)* | | | | |
| Total OPG electricity generation | **17.2** | 18.0 | **36.0** | 36.6 |
| Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities | **1.0** | 2.6 | **1.7** | 3.3 |
| | **18.2** | 20.6 | **37.7** | 39.9 |
| **Enterprise TGC per MWh *($/MWh)*** [1] | **55.78** | 48.72 | **52.71** | 48.35 |

[1] Amounts may not calculate due to rounding.

(3) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

| *(millions of dollars – except where noted)* | **Three Months Ended June 30** | | **Six Months Ended June 30** | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| Nuclear TGC | | | | |
| Regulated – Nuclear Generation OM&A expenses | **620** | 593 | **1,224** | 1,182 |
| Regulated – Nuclear Generation fuel expense | **62** | 68 | **135** | 136 |
| Regulated – Nuclear Generation capital expenditures | **319** | 375 | **632** | 741 |
| Less: Darlington Refurbishment capital and OM&A costs | **(258)** | (306) | **(517)** | (615) |
| Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts | **11** | 3 | **35** | 1 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(17)** | (16) | **(32)** | (29) |
| Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business | **(1)** | (1) | **(3)** | (2) |
| Other adjustments | **(1)** | (2) | **(2)** | (2) |
| | **735** | 714 | **1,472** | 1,412 |
| Nuclear electricity generation (TWh) | **8.6** | 9.3 | **19.0** | 19.3 |
| **Nuclear TGC per MWh (*$/MWh*)** [1] | **86.03** | 76.87 | **77.74** | 73.24 |

[1] Amounts may not calculate due to rounding.

(4) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Ranney Falls GS and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

| | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| *(millions of dollars – except where noted)* | **2018** | **2017** | **2018** | **2017** |
| Hydroelectric TGC | | | | |
| Regulated – Hydroelectric OM&A expenses | **82** | 75 | **162** | 151 |
| Regulated – Hydroelectric fuel expense | **90** | 97 | **155** | 170 |
| Contracted Generation Portfolio OM&A expenses | **43** | 40 | **84** | 79 |
| Contracted Generation Portfolio fuel expense | **14** | 13 | **31** | 27 |
| Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures | **64** | 48 | **100** | 85 |
| Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs | **(28)** | (19) | **(46)** | (35) |
| Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio | **(42)** | (41) | **(86)** | (80) |
| Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts | **(9)** | (15) | **(7)** | (24) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **15** | 23 | **21** | 34 |
| Other adjustments | **-** | 2 | **-** | 1 |
| | **229** | 223 | **414** | 408 |
| Adjusted hydroelectric electricity generation *(TWh)* | | | | |
| Regulated – Hydroelectric electricity generation | **7.6** | 8.2 | **15.3** | 16.2 |
| Contracted Generation Portfolio electricity generation | **1.0** | 0.5 | **1.7** | 1.1 |
| Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities | **1.0** | 2.6 | **1.7** | 3.3 |
| | **9.6** | 11.3 | **18.7** | 20.6 |
| **Hydroelectric TGC per MWh *($/MWh)*** [1] | **23.81** | 19.83 | **22.16** | 19.81 |

[1] Amounts may not calculate due to rounding.

(5) **Gross margin** is defined as revenue less fuel expense.

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# ONTARIO POWER GENERATION INC.

# INTERIM CONSOLIDATED FINANCIAL STATEMENTS
# (unaudited)

**JUNE 30, 2018**

ONTARIO POWER GENERATION

# INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

| *(millions of dollars except where noted)* | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Revenue** | **1,282** | 1,146 | **2,689** | 2,322 |
| Fuel expense | **166** | 178 | **321** | 333 |
| **Gross margin** | **1,116** | 968 | **2,368** | 1,989 |
| Operations, maintenance and administration | **743** | 711 | **1,465** | 1,419 |
| Depreciation and amortization | **198** | 172 | **384** | 339 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **247** | 236 | **494** | 474 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(212)** | (194) | **(422)** | (383) |
| Earnings from Fair Hydro Trust *(Note 16)* | **(8)** | - | **(12)** | - |
| Property taxes | **9** | 11 | **18** | 22 |
| Income from investments subject to significant influence | **(10)** | (8) | **(20)** | (18) |
| | **967** | 928 | **1,907** | 1,853 |
| **Income before other gains, interest and income taxes** | **149** | 40 | **461** | 136 |
| Other losses (gains) *(Note 19)* | **5** | (380) | **(254)** | (383) |
| **Income before interest and income taxes** | **144** | 420 | **715** | 519 |
| Net interest expense *(Note 5)* | **18** | 16 | **37** | 35 |
| **Income before income taxes** | **126** | 404 | **678** | 484 |
| Income tax expense *(Note 8)* | **-** | 97 | **13** | 109 |
| **Net income** | **126** | 307 | **665** | 375 |
| **Net income attributable to the Shareholder** | **121** | 303 | **656** | 367 |
| Net income attributable to non-controlling interest | **5** | 4 | **9** | 8 |
| **Basic and diluted earnings per share** *(dollars) (Note 14)* | **0.44** | 1.18 | **2.41** | 1.43 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

| *(millions of dollars)* | Three Months Ended June 30 | | Six Months Ended June 30 | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Net income** | **126** | 307 | **665** | 375 |
| **Other comprehensive income, net of income taxes** *(Note 9)* | | | | |
| Reclassification to income of amounts related to pension and other post-employment benefits [1] | **2** | 2 | **5** | 5 |
| Reclassification to income of losses on derivatives designated as cash flow hedges [2] | **5** | 5 | **9** | 9 |
| Unrealized loss on equity securities [3] | **-** | (7) | **-** | (2) |
| Other comprehensive income for the period | **7** | - | **14** | 12 |
| **Comprehensive income** | **133** | 307 | **679** | 387 |
| **Comprehensive income attributable to the Shareholder** | **128** | 303 | **670** | 379 |
| Comprehensive income attributable to non-controlling interest | **5** | 4 | **9** | 8 |

[1] Net of income tax expenses of $1 million for the three months ended June 30, 2018 and 2017. Net of income tax expenses of $2 million for the six months ended June 30, 2018 and 2017.

[2] Net of income tax expense of nil for the three months ended June 30, 2018 and 2017. Net of income tax expenses of $1 million for the six months ended June 30, 2018 and 2017.

[3] Net of income tax recovery of nil and $2 million for the three months ended June 30, 2018 and 2017. Net of income tax recovery of nil and $1 million for the six months ended June 30, 2018 and 2017, respectively.

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

| **Six Months Ended June 30**<br>*(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| **Operating activities** | | |
| Net income | **665** | 375 |
| Adjust for non-cash items: | | |
| Depreciation and amortization | **384** | 339 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **494** | 474 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(422)** | (383) |
| Pension and other post-employment benefit costs *(Note 10)* | **198** | 226 |
| Deferred income taxes | **(14)** | 16 |
| Regulatory assets and regulatory liabilities | **(142)** | (73) |
| Other gains *(Note 19)* | **(250)** | (379) |
| Other | **(17)** | (9) |
| Expenditures on fixed asset removal and nuclear waste management | **(144)** | (157) |
| Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management | **44** | 41 |
| Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans | **(163)** | (180) |
| Distributions received from investments subject to significant influence | **25** | 23 |
| Net changes to other long-term assets and long-term liabilities | **86** | 69 |
| Net changes to non-cash working capital balances *(Note 17)* | **(105)** | (125) |
| **Cash flow provided by operating activities** | **639** | 257 |
| **Investing activities** | | |
| Acquisition of Fair Hydro Trust financing receivables | **(609)** | - |
| Proceeds from deposit note | **-** | 70 |
| Net proceeds from sale of property, plant and equipment | **273** | 484 |
| Investment in property, plant and equipment and intangible assets | **(807)** | (855) |
| **Cash flow used in investing activities** | **(1,143)** | (301) |
| **Financing activities** | | |
| Issuance of Class A shares *(Note 13)* | **268** | - |
| Issuance of OPG long-term debt *(Note 5)* | **1,047** | 300 |
| Repayment of OPG long-term debt | **(327)** | (212) |
| Issuance of Fair Hydro Trust long-term debt *(Note 5)* | **1,206** | - |
| Repayment of Fair Hydro Trust revolving warehouse debt | **(900)** | - |
| Distribution to non-controlling interest | **(10)** | (7) |
| Contribution from non-controlling interest | **-** | 19 |
| Dividend to the Province's Consolidated Revenue Fund *(Note 18)* | **(283)** | - |
| Issuance of short-term debt | **2,549** | 864 |
| Repayment of short-term debt | **(2,695)** | (864) |
| **Cash flow provided by financing activities** | **855** | 100 |
| Net increase in cash, cash equivalents and restricted cash | **351** | 56 |
| **Cash, cash equivalents and restricted cash, beginning of period** | **234** | 186 |
| **Cash, cash equivalents and restricted cash, end of period** | **585** | 242 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| As at<br>*(millions of dollars)* | June 30<br>2018 | December 31<br>2017 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash, cash equivalents and restricted cash *(Note 3)* | **585** | 234 |
| Equity securities | **151** | 188 |
| Receivables from related parties | **406** | 369 |
| Nuclear fixed asset removal and nuclear waste management funds | **22** | 23 |
| Fuel inventory | **312** | 309 |
| Materials and supplies | **102** | 103 |
| Regulatory assets *(Note 4)* | **340** | - |
| Income taxes recoverable | **17** | - |
| Prepaid expenses | **158** | 192 |
| Other current assets | **90** | 146 |
| | **2,183** | 1,564 |
| **Property, plant and equipment** | **30,684** | 29,950 |
| Less: accumulated depreciation | **8,929** | 8,628 |
| | **21,755** | 21,322 |
| **Intangible assets** | **320** | 565 |
| Less: accumulated amortization | **193** | 432 |
| | **127** | 133 |
| **Other assets** | | |
| Nuclear fixed asset removal and nuclear waste management funds | **17,076** | 16,701 |
| Financing receivables | **1,788** | 1,179 |
| Long-term materials and supplies | **334** | 355 |
| Regulatory assets *(Note 4)* | **7,057** | 7,231 |
| Investments subject to significant influence | **304** | 309 |
| Other long-term assets | **52** | 28 |
| | **26,611** | 25,803 |
| | **50,676** | 48,822 |

*See accompanying notes to the interim consolidated financial statements*

# INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

| As at<br>*(millions of dollars)* | June 30<br>2018 | December 31<br>2017 |
|---|---|---|
| **Liabilities** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | **1,096** | 1,228 |
| Short-term debt *(Note 6)* | **114** | 260 |
| Deferred revenue due within one year | **6** | 12 |
| Long-term debt due within one year *(Note 5)* | **288** | 398 |
| Income taxes payable | **-** | 80 |
| Regulatory liabilities *(Note 4)* | **25** | - |
| | **1,529** | 1,978 |
| **Long-term debt** *(Note 5)* | **7,057** | 5,921 |
| **Other liabilities** | | |
| Fixed asset removal and nuclear waste management liabilities *(Note 7)* | **20,838** | 20,421 |
| Pension liabilities | **3,354** | 3,423 |
| Other post-employment benefit liabilities | **3,140** | 3,092 |
| Long-term accounts payable and accrued charges | **252** | 252 |
| Deferred revenue | **385** | 351 |
| Deferred income taxes | **949** | 879 |
| Regulatory liabilities *(Note 4)* | **614** | 594 |
| | **29,532** | 29,012 |
| **Equity** | | |
| Common shares *(Note 13)* | **5,126** | 5,126 |
| Class A shares *(Note 13)* | **787** | 519 |
| Retained earnings | **6,753** | 6,396 |
| Accumulated other comprehensive loss *(Note 9)* | **(272)** | (295) |
| **Equity attributable to the Shareholder** | **12,394** | 11,746 |
| Equity attributable to non-controlling interest | **164** | 165 |
| **Total equity** | **12,558** | 11,911 |
| | **50,676** | 48,822 |

# INTERIM CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY (UNAUDITED)

| **Six Months Ended June 30**<br>*(millions of dollars)* | **2018** | **2017** |
|---|---|---|
| **Common shares** *(Note 13)* | **5,126** | 5,126 |
| **Class A shares** *(Note 13)* | | |
| Balance at beginning of period | **519** | - |
| Issuance of Class A shares | **268** | - |
| Balance at end of period | **787** | - |
| **Retained earnings** | | |
| Balance at beginning of period | **6,396** | 5,534 |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **(9)** | - |
| Adjustment to recognize income tax effects of intercompany transfer of assets to opening retained earnings *(Note 2)* | **(7)** | - |
| | **6,380** | 5,534 |
| Net income attributable to the Shareholder | **656** | 367 |
| Dividend to the Province's Consolidated Revenue Fund *(Note 18)* | **(283)** | - |
| Reclassification of non-controlling interest on change in ownership interest | **-** | 2 |
| Balance at end of period | **6,753** | 5,903 |
| **Accumulated other comprehensive loss, net of income taxes** | | |
| Balance at beginning of period | **(295)** | (295) |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **9** | - |
| Reclassification of non-controlling interest on change in ownership interest | **-** | 3 |
| | **(286)** | (292) |
| Other comprehensive income | **14** | 12 |
| Balance at end of period | **(272)** | (280) |
| **Equity attributable to the Shareholder** | **12,394** | 10,749 |
| **Equity attributable to non-controlling interest** | | |
| Balance at beginning of period | **165** | 143 |
| Equity contribution from non-controlling interest | **-** | 21 |
| Reclassification of non-controlling interest on change in ownership interest | **-** | (5) |
| Distribution to non-controlling interest | **(10)** | (7) |
| Income attributable to non-controlling interest | **9** | 8 |
| Balance at end of period | **164** | 160 |
| **Total equity** | **12,558** | 10,909 |

*See accompanying notes to the interim consolidated financial statements*

# NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and six months ended June 30, 2018 and 2017

## 1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and six months ended June 30, 2018 and 2017 include the accounts of Ontario Power Generation Inc. (OPG or the Company) and its subsidiaries. The Company consolidates its interest in entities over which it is able to exercise control and attributes the results to its sole shareholder, the Province of Ontario (Province). Interests owned by other parties are reflected as non-controlling interest. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP). These interim consolidated financial statements do not contain all of the disclosures required by US GAAP for annual financial statements. Accordingly, they should be read in conjunction with the annual consolidated financial statements of the Company as at and for the year ended December 31, 2017.

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG has also received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

In April 2018, OPG received an extension to its previous exemptive relief from the OSC. The exemptive relief will now terminate on the earliest of the following:

- January 1, 2024
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2017 comparative amounts have been reclassified from financial statements previously presented to conform to the 2018 interim consolidated financial statement presentation.

### Use of Management Estimates

The preparation of interim consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the interim consolidated financial statements, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations and associated asset retirement costs capitalized as part of property, plant and equipment, income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, valuation of derivative instruments and investments in segregated funds, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

## 2. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

### New Accounting Standards Effective in 2018

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services.

Effective January 1, 2018, OPG adopted Topic 606, including relevant practical expedients, utilizing the modified retrospective approach to implement the transition. No differences in the timing or amount of revenue recognition were identified as a result of the adoption of the new standard. The adoption of Topic 606 has required OPG to amend its accounting policy with respect to revenue recognition, as described below.

*Revenue from Contracts with Customers – Regulated Generation*

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the Ontario Energy Board (OEB) that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electrical System Operator (IESO). For electricity generated from its regulated nuclear and regulated hydroelectric facilities, OPG receives payment from the IESO on a monthly basis based on regulated prices authorized by the OEB. OPG's performance obligation with respect to regulated generation is to supply electricity generated from its regulated nuclear and regulated hydroelectric facilities to the wholesale electricity market in Ontario. The Company has determined that this performance obligation is satisfied over time; OPG utilizes the output method under Topic 606 to recognize revenue by applying the relevant base regulated price and rate riders as applicable to each unit of electricity generated and metered to the IESO. This methodology reflects the real-time nature of electricity generation and the underlying performance obligation, of which no portion remains unsatisfied at the end of the applicable reporting period. During interim rate periods authorized by the OEB, revenue is recognized on the basis of interim regulated prices set by the OEB. In instances where a subsequent OEB decision results in a difference between final regulated prices retroactively effective for the interim period and the interim regulated prices, OPG records the resulting adjustment to revenue in connection with that period based on the OEB's decision. Any resulting revenue shortfall in connection with the interim rate period is collected prospectively from the IESO in the manner authorized by the OEB. OPG's receivables in connection with electricity generated from its regulated nuclear and regulated hydroelectric facilities are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

Regulated prices currently in effect for OPG's regulated nuclear and regulated hydroelectric generation were established by the OEB's December 2017 decision and March 2018 payment amounts order on OPG's 2016 application for new regulated prices for the 2017-2021 period. In the decision, the OEB set an effective date for the new base regulated prices of June 1, 2017. Pursuant to the decision, the new base regulated prices are determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices are determined using a formula that annually escalates the previously approved base regulated prices, subject to some adjustments,

based on an industry-specific weighted inflation factor reflecting indices published annually by the OEB, less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices are determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to *Ontario Regulation 53/05*, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years is based on the OEB-allowed level of operating costs including depreciation and amortization expenses and a return on rate base, less a stretch factor adjustment. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The difference between the non-deferred portion of the nuclear revenue requirement, calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. See Note 4 for further information on the March 2018 payment amounts order and the Rate Smoothing Deferral Account.

Base regulated prices in effect for the period January 1, 2017 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs (including depreciation and amortization expenses) for the regulated facilities for 2014 and 2015 and a return on rate base.

*Revenue from Contracts with Customers – Non-regulated Generation and Other Contract Revenue*

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. The IESO is the counterparty to all ESAs and other contractual arrangements that are currently in effect. As at December 31, 2017, most of OPG's operating non-regulated generating assets are subject to an ESA. As permitted by the practical expedient within Topic 606, revenue from the generating stations subject to an ESA is recognized in the amount that OPG has a right to invoice on a monthly basis to the IESO as the Company satisfies its performance obligation in accordance with the terms of the agreement to supply energy and capacity from the applicable facilities to Ontario's wholesale energy market. No portion of OPG's performance obligation remains unsatisfied at the end of any applicable reporting period. OPG estimates revenues for variable or conditional amounts under each ESA using a most likely amount approach on a contract-by-contract basis. Variable consideration under each ESA is included in revenue only to the extent that it is probable that the amount will not be subject to significant reversal when the underlying uncertainty is resolved. OPG's receivables in connection with electricity generated from its non-regulated assets are part of the Company's electricity related receivables from the IESO, representing OPG's unconditional right to payment for satisfying its performance obligation wherein only the passage of time is required before payment is received. For further discussion, refer to Note 11.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and mid-west regions of the United States. Under these arrangements, OPG's performance obligation is to either physically supply energy or provide capacity, depending on the contract, to a counterparty in a control area outside of Ontario. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income.

OPG also derives non-energy revenue under the terms of a lease arrangement and associated, non-lease agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. The associated agreements include revenue from heavy water sales, detritiation services and nuclear waste management services. Revenues under these associated agreements are recognized as services are provided or when products are delivered, therein satisfying OPG's performance obligation.

In addition, non-energy revenue includes isotope sales and other service revenues. Revenues from these activities are recognized as the respective performance obligations are satisfied, in accordance with the terms stipulated in the respective contracts.

*Revenue Recognition – Leasing Revenue*

The minimum lease payments stemming from OPG's lease arrangement with Bruce Power related to the Bruce nuclear generating stations are recognized in revenue on a straight-line basis over the term of the lease. Similarly, revenue from real estate rentals is recognized over the term of the lease as the Company renders the requisite services outlined in the respective contracts.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities are required to measure equity investments at fair value and recognize any changes in fair value in net income. The update is effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for securities is no longer available. Effective January 1, 2018, any unrealized gains and losses related to equity securities are recognized in net income instead of other comprehensive income.

As a result of the adoption of the new guidance, the unrealized cumulative after-tax loss of $9 million on AFS securities reported in accumulated other comprehensive income as at December 31, 2017 was reclassified to opening retained earnings as of January 1, 2018. There were no other impacts on OPG's consolidated financial statements upon adoption of the new guidance, other than to replace the accounting policy for AFS securities with a new policy for holdings of equity securities as described below.

*Equity Securities*

Equity securities held by OPG are measured at fair value, with gains and losses due to changes in fair value recognized within other gains and losses in the consolidated statement of income. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period in which dividends are declared. Equity securities are initially measured at the transaction price.

Restricted Cash Disclosures

In November 2016, the FASB issued ASU No. 2016-18, *Statement of Cash Flows* (Topic 230): *Restricted Cash (a consensus of the FASB Emerging Issues Task Force)*, which clarifies how entities should present restricted cash and restricted cash equivalents in the statement of cash flows. The guidance is effective for OPG's 2018 fiscal year, including interim periods, and is applied retrospectively. The changes in disclosures required under this update are reflected in the interim consolidated statements of cash flows and Note 3.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits* (Topic 715): *Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

Effective January 1, 2018, OPG adopted the new provisions of Topic 715. Adoption of these provisions did not impact OPG's consolidated financial statements, as OPG capitalized only the service cost component of

postretirement benefits costs prior to the adoption of the new guidance. Additionally, OPG previously included the service cost component of postretirement benefit costs with other compensation costs within operations, maintenance and administration expenses in the consolidated statements of income, and did not show a subtotal of income from operations prior to the adoption of the new guidance. As such, the new guidance did not affect the presentation of OPG's consolidated financial statements or result in changes in OPG's accounting policies.

Intra-entity Transfers of Assets Other than Inventory

In October 2016, the FASB issued ASU 2016-16, *Income Taxes* (Topic 740): *Intra-Entity Transfers of Assets Other than Inventory*, to amend existing guidance with respect to accounting for the income tax effects of intra-entity asset transfers within the consolidated group. Effective January 1, 2018, entities are required to recognize the income tax effects of all intra-entity asset transfers, with the exception of inventory, as soon as the transfer occurs. Previously, entities were required to defer recognition of such income tax effects until the asset was sold to a third party.

The update is effective for OPG beginning January 1, 2018 and is required to be applied on a modified retrospective basis. On adoption of the update, the Company recorded an adjustment reducing opening retained earnings by $7 million to reflect the associated deferred income tax liability resulting from the cumulative effect of OPG's transfer of assets, other than inventory, to the UMH Energy Limited Partnership (UMH) and the Lower Mattagami Energy Limited Partnership (LME) in prior years. Adoption of this update did not otherwise impact the Company's consolidated financial statements, other than through an addition to OPG's accounting policy for income taxes as described below.

*Income Taxes – Intra-entity Transfers of Non-inventory Assets*

The income tax impact of any intra-entity transfers of non-inventory assets is recognized upon the occurrence of the transfer.

**Recent Accounting Pronouncements Not Yet Adopted**

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under *Leases* (Topic 840). The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In July 2018, the FASB issued ASU No. 2018-11, *Leases (Topic 842) – Targeted Improvements* wherein entities can utilize an additional optional transition method to apply the new lease accounting standard at the effective date of January 1, 2019. The cumulative impact from adopting the new standard would be recognized as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or have expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company has implemented a comprehensive project governance framework to oversee the transition to the new leasing guidance, comprised of a Steering Committee, Implementation and Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross-functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. Management has performed procedures to determine the completeness of leasing arrangements that the Company has entered into. During the remainder of the year, management will review the identified leasing arrangements to quantify the impact of adopting Topic 842, and will determine which practical expedients, if any, the Company will elect to apply as part of the implementation of the standard.

## 3. CASH, CASH EQUIVALENTS AND RESTRICTED CASH

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

Cash, cash equivalents, and restricted cash consist of the following:

| **As at**<br>*(millions of dollars)* | **June 30 2018** | **December 31 2017** |
|---|---|---|
| Cash and cash equivalents | **118** | 230 |
| Restricted cash | **467** | 4 |
| Total cash, cash equivalents and restricted cash | **585** | 234 |

The Fair Hydro Trust's (the Trust) cash on deposit is subject to contractual restrictions of the Trust's Master Trust Indenture. All of the Trust's bank accounts are under the name and exclusive control of its indenture trustee. Amounts on deposit are restricted in purpose and the distribution of use is subject to the order of payment priority outlined in the Trust's Master Trust Indenture.

Proceeds from OPG's green bond issuance are restricted in purpose and are to be used solely to finance eligible projects that offer tangible environmental benefits, as defined in OPG's Green Bond Framework. The proceeds from the first green bond issuance in June 2018 are to be used to finance eligible hydroelectric projects and are held in a segregated account. In July 2018, approximately $297 million was released from the segregated account, representing funds invested in the eligible hydroelectric projects during the second half of 2016 and 2017.

## 4. REGULATORY ASSETS AND REGULATORY LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and interveners on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017-2021 period and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's OEB-authorized regulatory variance and deferral accounts (regulatory accounts), with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. In January 2018, OPG submitted a draft payment amounts order to the OEB to reflect the December 2017 decision's findings.

In March 2018, the OEB issued the final payment amounts order on OPG's application for new regulated prices. With respect to the regulatory accounts, the payment amounts order authorized OPG to collect, through rate riders on nuclear and regulated hydroelectric production, the approved amount of $305 million over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and December 31, 2020. Any shortfall or over-recovery of the approved balance due to differences between actual and forecast production is to be recorded in the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account authorized by the OEB.

Amortization of regulatory assets and regulatory liabilities for regulatory account balances approved for disposition in the OEB's March 2018 payment amounts order is recorded on a straight-line basis, effective March 1, 2018, based on the portion of the balances authorized to be collected during the applicable period.

The payment amounts order set a rate smoothing approach and resulting nuclear base regulated prices effective June 1, 2017 such that no amounts are to be deferred in the Rate Smoothing Deferral Account for 2017, 2018 and 2021. Pursuant to the payment amounts order, approximately $500 million is to be deferred in the Rate Smoothing Deferral Account over the 2019-2020 period. The approved rate smoothing approach and nuclear base regulated prices represented an adjustment to the proposal in OPG's January 2018 draft payment amounts order, which was the basis for management's best estimate of the impact of the OEB's December 2017 decision recorded in the fourth quarter of 2017. To reflect this adjustment, in the first quarter of 2018, the Company recorded a reduction of $67 million in the Interim Period Shortfall Revenue regulatory asset previously recognized as of December 31, 2017 and a reversal of the $63 million regulatory liability for the Rate Smoothing Deferral Account previously recognized as of December 31, 2017.

For the regulated hydroelectric facilities, the payment amounts order set base regulated prices for the June 1, 2017 to December 31, 2017 period and for the January 1, 2018 to December 31, 2018 period as calculated by OPG in the draft payment amounts order, based on the incentive regulation formula approved in the December 2017 decision and inflation indices published by the OEB. For the 2019-2021 period, the base regulated prices for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and published indices.

The payment amounts order authorized separate rate riders on nuclear and regulated hydroelectric production for the collection of the June 1, 2017 to February 28, 2018 interim period revenue shortfall over the period March 1, 2018 to December 31, 2020, with 15 percent of the balance to be recovered between March 1, 2018 and December 31, 2018, 50 percent between January 1, 2019 and December 31, 2019, and 35 percent between January 1, 2020 and December 31, 2020. The Interim Period Revenue Shortfall regulatory asset is reversed as these riders are collected.

The regulatory assets and liabilities recorded as at June 30, 2018 and December 31, 2017 are as follows:

| *(millions of dollars)* | **June 30 2018** | **December 31 2017** |
|---|---|---|
| Regulatory assets | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Pension and OPEB Cost Variance Account | **699** | 716 |
| Pension & OPEB Cash Versus Accrual Differential Deferral Account | **691** | 614 |
| Hydroelectric Surplus Baseload Generation Variance Account | **418** | 360 |
| Bruce Lease Net Revenues Variance Account | **134** | 121 |
| Other variance and deferral accounts | **121** | 124 |
| | **2,063** | 1,935 |
| Interim Period Revenue Shortfall | **586** | 544 |
| Pension and OPEB Regulatory Asset *(Note 10)* | **3,757** | 3,855 |
| Deferred Income Taxes | **991** | 897 |
| Total regulatory assets | **7,397** | 7,231 |
| Less: current portion | **340** | - |
| Non-current regulatory assets | **7,057** | 7,231 |
| Regulatory liabilities | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Pension & OPEB Cash Payment Variance Account | **171** | 140 |
| Hydroelectric Water Conditions Variance Account | **163** | 150 |
| Changes in Station End-of-Life Dates (December 31, 2015) Deferral Account | **103** | 103 |
| Other variance and deferral accounts | **202** | 201 |
| Total regulatory liabilities | **639** | 594 |
| Less: current portion | **25** | - |
| Non-current regulatory liabilities | **614** | 594 |

In May 2018, pursuant to an accounting order application filed by OPG in December 2017, the OEB authorized the establishment of a new Impact Resulting from Changes to Pickering Station End-of-Life Dates (December 31, 2017) Deferral Account, effective January 1, 2018, on a final basis. The purpose of the account is to record the revenue requirement impact of the changes to nuclear fixed asset removal and nuclear waste management liabilities and depreciation and amortization expenses resulting from the changes to the accounting end-of-life assumptions for OPG's Pickering nuclear generating station (GS) implemented effective December 31, 2017. As of June 30, 2018, OPG recognized a regulatory liability of $62 million related to the balance in the deferral account.

## 5. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following:

| *(millions of dollars)* | **June 30 2018** | **December 31 2017** |
|---|---|---|
| Senior notes payable to the Ontario Electricity Financial Corporation | **3,470** | 3,195 |
| Medium Term Notes | **950** | 500 |
| UMH Energy Partnership project debt | **179** | 181 |
| PSS Generating Station Limited Partnership project debt | **245** | 245 |
| Lower Mattagami Energy Limited Partnership project debt | **1,595** | 1,595 |
| Fair Hydro Trust senior debt | **912** | 601 |
| Other | **19** | 19 |
| | **7,370** | 6,336 |
| Less: unamortized bond issuance fees | **(25)** | (17) |
| Less: amounts due within one year | **(288)** | (398) |
| Long-term debt | **7,057** | 5,921 |

In the first quarter of 2018, OPG issued a total of $600 million senior notes payable to the Ontario Electricity Financial Corporation maturing in 2048. The effective and coupon interest rates on these notes ranged from 3.87 percent to 4.00 percent. In June 2018, OPG issued an inaugural green bond offering of $450 million under its Medium Term Note Program maturing in 2048. The effective and coupon interest rates on these bonds are 3.92 percent and 3.84 percent, respectively.

In December 2017, the Fair Hydro Trust entered into an $800 million two-year senior revolving warehouse facility agreement with an expiry date of December 2019. In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity in May 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued to provide a portion of the funding requirement for the Trust's purchase of Investment Interest from the IESO in December 2017.

In March 2018, the Trust purchased an Investment Interest from the IESO in the amount of $460 million. Approximately $235 million was financed by the Trust through the revolving warehouse facility, and the remaining $225 million was financed through the issuance of subordinated debt to OPG. In April 2018, the Trust purchased an Investment Interest from the IESO in the amount of $149 million. Approximately $76 million was financed by the Trust through the revolving warehouse facility, and the remaining $73 million was funded through the issuance of subordinated debt to OPG.

In April 2018, subsequent to the purchase of the Investment Interest, the Trust issued $400 million of senior notes payable with a coupon interest rate of 3.52 percent and an effective interest rate of 3.60 percent, payable semi-annually until maturity in May 2038. The proceeds were used to repay the majority of the balance of the revolving warehouse facility outstanding after the April 2018 Investment Interest acquisition. The outstanding balance of the revolving warehouse facility of $12 million has been reclassified as long-term debt as at June 30, 2018 reflecting the contractual terms of the facility agreement.

During the first quarter of 2018, $275 million of OPG long-term debt and $500 million of Fair Hydro Trust revolving warehouse facility debt were repaid. During the second quarter of 2018, $52 million of OPG long-term debt and $400 million of Fair Hydro Trust revolving warehouse facility debt were repaid.

The following table summarizes the net interest expense:

| *(millions of dollars)* | Three Months Ended June 30 2018 | 2017 | Six Months Ended June 30 2018 | 2017 |
|---|---|---|---|---|
| Interest on long-term debt [1] | **70** | 71 | **140** | 141 |
| Interest on short-term debt | **4** | 2 | **4** | 2 |
| Interest income | **(2)** | (2) | **(3)** | (2) |
| Interest capitalized to property, plant and equipment and intangible assets | **(47)** | (40) | **(91)** | (82) |
| Interest related to regulatory assets and liabilities [2] | **(7)** | (15) | **(13)** | (24) |
| Net interest expense | **18** | 16 | **37** | 35 |

[1] Excludes interest on Fair Hydro Trust senior debt and interest on OPG's debt attributed to funding a portion of OPG's purchase of the Trust's subordinated debt. These interest costs have been included in earnings from Fair Hydro Trust in the interim consolidated statements of income. Refer to Note 16 for further details.

[2] Includes interest to recognize the cost of financing related to variance and deferral accounts, as authorized by the OEB, and interest costs deferred in certain variance and deferral accounts.

## 6. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2018, OPG renewed and extended the expiry date of both tranches from May 2022 to May 2023. There were no amounts outstanding under the bank credit facility as at June 30, 2018 and December 31, 2017. There was no commercial paper outstanding under OPG's commercial paper program as at June 30, 2018 (December 31, 2017 – $100 million). The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately one percent and for less than one year in duration.

As at June 30, 2018, LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at June 30, 2018, there was $114 million of external commercial paper outstanding under LME's commercial paper program (December 31, 2017 − $160 million). A letter of credit of $55 million was issued in July 2017 and remains outstanding as at June 30, 2018, under the $300 million tranche of the LME's credit facility.

As at June 30, 2018, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $464 million of short-term, uncommitted credit facilities, which support the issuance of letters of credit. OPG uses letters of credit to support its supplementary pension plans and for other general corporate purposes. As at June 30, 2018, a total of $393 million of letters of credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $39 million for general corporate purposes, and $1 million related to the operation of the Portland Energy Centre.

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at June 30, 2018, there were letters of credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby letters of credit facilities in support of its operations. As at June 30, 2018, total letters of credit of $15 million had been issued under these facilities.

## 7. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at June 30, 2018 and December 31, 2017 consist of the following:

| As at<br>*(millions of dollars)* | June 30<br>2018 | December 31<br>2017 |
|---|---|---|
| Liability for nuclear used fuel management | **12,245** | 11,970 |
| Liability for nuclear decommissioning and nuclear low and intermediate level waste management | **8,256** | 8,107 |
| Liability for non-nuclear fixed asset removal | **337** | 344 |
| Fixed asset removal and nuclear waste management liabilities | **20,838** | 20,421 |

## 8. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments and records an offsetting regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Income tax expense for the three months ended June 30, 2018 was reduced due to a higher amount of deferred income tax expense recorded as a regulatory asset.

Income tax expense for the six months ended June 30, 2018 was reduced as a result of a refundable tax credit of $86 million arising on payment of the dividend during the first quarter of 2018 (see Note 18) and a higher amount of deferred income tax expense recorded as a regulatory asset.

## 9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

| | Six Months Ended June 30, 2018 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Losses on Cash Flow Hedges** | **Pension and OPEB** | **Equity Securities** | **Total** |
| AOCL, beginning of period | **(66)** | **(220)** | **(9)** | **(295)** |
| Reclassification of cumulative unrealized losses on equity securities to opening retained earnings *(Note 2)* | **-** | **-** | **9** | **9** |
| | **(66)** | **(220)** | **-** | **(286)** |
| Amounts reclassified from AOCL | **9** | **5** | **-** | **14** |
| Other comprehensive income for the period | **9** | **5** | **-** | **14** |
| AOCL, end of period | **(57)** | **(215)** | **-** | **(272)** |

| | Six Months Ended June 30, 2017 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Losses on Cash Flow Hedges** | **Pension and OPEB** | **Equity Securities** | **Total** |
| AOCL, beginning of period | (87) | (207) | (1) | (295) |
| Unrealized loss on equity securities | - | - | (2) | (2) |
| Amounts reclassified from AOCL | 9 | 5 | - | 14 |
| Other comprehensive income (loss) for the period | 9 | 5 | (2) | 12 |
| Reclassification of non-controlling interest on change in ownership interest | 3 | - | - | 3 |
| AOCL, end of period | (75) | (202) | (3) | (280) |

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and six months ended June 30, 2018 are as follows:

| | Amount Reclassified from AOCL | | |
|---|---|---|---|
| *(millions of dollars)* | **Three Months Ended June 30, 2018** | **Six Months Ended June 30, 2018** | **Statement of Income Line Item** |
| Amortization of losses from cash flow hedges | | | |
| Losses | **5** | **10** | Net interest expense |
| Income tax recovery | **-** | **(1)** | Income tax expense |
| | **5** | **9** | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses | **3** | **7** | See (1) below |
| Income tax recovery | **(1)** | **(2)** | Income tax expense |
| | **2** | **5** | |
| Total reclassifications for the period | **7** | **14** | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and six months ended June 30, 2017 are as follows:

| | Amount Reclassified from AOCL | | |
|---|---|---|---|
| *(millions of dollars)* | Three Months Ended June 30, 2017 | Six Months Ended June 30, 2017 | Statement of Income Line Item |
| Amortization of losses from cash flow hedges | | | |
| Losses | 5 | 10 | Net interest expense |
| Income tax recovery | - | (1) | Income tax expense |
| | 5 | 9 | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses | 3 | 7 | See (1) below |
| Income tax recovery | (1) | (2) | Income tax expense |
| | 2 | 5 | |
| Total reclassifications for the period | 7 | 14 | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

## 10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's pension and OPEB costs for the three months ended June 30, 2018 and 2017 are as follows:

| | Registered Pension Plans | | Supplementary Pension Plans | | Other Post-Employment Benefits | |
|---|---|---|---|---|---|---|
| *(millions of dollars)* | **2018** | **2017** | **2018** | **2017** | **2018** | **2017** |
| *Components of Cost Recognized for the period* | | | | | | |
| Current service costs | **82** | 69 | **2** | 2 | **20** | 17 |
| Interest on projected benefit obligation | **141** | 136 | **3** | 3 | **28** | 27 |
| Expected return on plan assets, net of expenses | **(205)** | (192) | **-** | - | **-** | - |
| Amortization of net actuarial loss [1] | **50** | 46 | **1** | 1 | **1** | - |
| Costs recognized [2] | **68** | 59 | **6** | 6 | **49** | 44 |

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the three months ended June 30, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $49 million (three months ended June 30, 2017 – $44 million).

[2] These pension and OPEB costs for the three months ended June 30, 2018 exclude the net reduction of costs of $24 million from the recognition of changes in the regulatory assets and regulatory liabilities for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (three months ended June 30, 2017 – net addition of costs of $4 million).

OPG's pension and OPEB costs for the six months ended June 30, 2018 and 2017 are as follows:

| *(millions of dollars)* | Registered Pension Plans | | Supplementary Pension Plans | | Other Post-Employment Benefits | |
|---|---|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** | **2018** | **2017** |
| *Components of Cost Recognized for the period* | | | | | | |
| Current service costs | **165** | 137 | **4** | 3 | **40** | 34 |
| Interest on projected benefit obligation | **283** | 273 | **6** | 6 | **54** | 54 |
| Expected return on plan assets, net of expenses | **(410)** | (383) | **-** | - | **-** | - |
| Amortization of net actuarial loss [1] | **99** | 92 | **3** | 3 | **3** | - |
| Cost recognized [2] | **137** | 119 | **13** | 12 | **97** | 88 |

[1] The amortization of net actuarial loss is recognized as an increase to other comprehensive income. This increase for the six months ended June 30, 2018 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $98 million (six months ended June 30, 2017 – $88 million).

[2] These pension and OPEB costs for the six months ended June 30, 2018 exclude the net reduction of costs of $49 million from the recognition of changes in the regulatory assets and regulatory liabilities for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the Pension & OPEB Cash Payment Variance Account (six months ended June 30, 2017 − net addition of costs of $7 million).

## 11. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/United States (US) foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars (USD). OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. OPG's electricity related accounts receivable from the IESO constituted of $379 million as at June 30, 2018 (December 31, 2017 − $354 million). The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at June 30, 2018 was less than $1 million.

The fair value of the outstanding derivatives was nil as at June 30, 2018 (December 31, 2017 – totalled a net liability of $20 million).

Existing pre-tax net losses of $18 million deferred in AOCL as at June 30, 2018 are expected to be reclassified to net income within the next 12 months.

## 12. FAIR VALUE MEASUREMENTS

The fair value of financial instruments traded in active markets is based on quoted market prices at the interim consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments. The fair value hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the interim consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

Transfers into, out of, or between fair value hierarchy levels are deemed to occur on the date of the event or change in circumstances that causes the transfer to occur.

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, references to current fair values of other investments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value. Pooled funds are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices.

Certain investments within the Nuclear Segregated Fund's real assets portfolio are measured at fair value by their investment managers using net asset value (NAV). Investments measured at NAV as a practical expedient for determining their fair value are excluded from the fair value hierarchy.

The following is a summary of OPG's financial instruments and their fair value as at June 30, 2018 and December 31, 2017:

| | Fair Value | | Carrying Value [1] | | |
|---|---|---|---|---|---|
| *(millions of dollars)* | **June 30 2018** | **December 31 2017** | **June 30 2018** | **December 31 2017** | **Balance Sheet Line Item** |
| Nuclear Segregated Funds (includes current portion) [2] | **17,098** | 16,724 | **17,098** | 16,724 | Nuclear fixed asset removal and nuclear waste management funds |
| Financing receivables | **1,883** | 1,179 | **1,788** | 1,179 | Financing receivables |
| Investment in Hydro One shares | **151** | 188 | **151** | 188 | Equity securities |
| Payable related to cash flow hedges | **(36)** | (40) | **(36)** | (40) | Long-term accounts payable and accrued charges |
| Long-term debt – OPG (includes current portion) | **(6,922)** | (6,234) | **(6,458)** | (5,735) | Long-term debt |
| Long-term debt – Fair Hydro Trust | **(946)** | (601) | **(912)** | (601) | Long-term debt |
| Other financial instruments | **31** | (16) | **31** | (16) | Various |

[1] The carrying values of other financial instruments included in cash, cash equivalents and restricted cash, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the Ontario Nuclear Funds Agreement when the Nuclear Segregated Funds are in a surplus position.

The fair value of the Fair Hydro Trust long-term senior debt including the warehouse credit facility and OPG's long-term debt issued under the Medium Term Note Program is based on indicative pricing from the market. The fair value of these debt instruments is based on Level 2 inputs. The fair value of all other long-term debt instruments is determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

For the financing receivables related to the Investment Interests acquired from the IESO, fair value is based on projected cash flows and expected returns on the financing receivables. Therefore, the fair value of the financing receivables is based on Level 3 inputs.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at June 30, 2018 and December 31, 2017:

| | June 30, 2018 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **5,982** | **4,999** | **-** | **10,981** |
| Investments measured at NAV [1] | | | | **1,431** |
| | | | | **12,412** |
| Due to Province | | | | **(2,648)** |
| Used Fuel Segregated Fund, net | | | | **9,764** |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **4,515** | **3,680** | **-** | **8,195** |
| Investments measured at NAV [1] | | | | **1,174** |
| | | | | **9,369** |
| Due to Province | | | | **(2,035)** |
| Decommissioning Segregated Fund, net | | | | **7,334** |
| Investment in equity securities | **151** | **-** | **-** | **151** |
| Other financial assets | **1** | **-** | **39** | **40** |
| **Liabilities** | | | | |
| Other financial liabilities | **(8)** | **(1)** | **-** | **(9)** |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

| *(millions of dollars)* | December 31, 2017 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 6,090 | 4,705 | - | 10,795 |
| Investments measured at NAV [1] | | | | 1,292 |
| | | | | 12,087 |
| Due to Province | | | | (2,529) |
| Used Fuel Segregated Fund, net | | | | 9,558 |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 4,547 | 3,487 | - | 8,034 |
| Investments measured at NAV [1] | | | | 1,065 |
| | | | | 9,099 |
| Due to Province | | | | (1,933) |
| Decommissioning Segregated Fund, net | | | | 7,166 |
| Investment in equity securities | 188 | - | - | 188 |
| Other financial assets | 5 | 3 | 6 | 14 |
| **Liabilities** | | | | |
| Other financial liabilities | (28) | (2) | - | (30) |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the interim consolidated balance sheets.

During the six months ended June 30, 2018, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the three months ended June 30, 2018:

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, April 1, 2018 | **10** |
| Realized losses included in revenue | **(2)** |
| Purchases | **31** |
| Closing balance, June 30, 2018 | **39** |

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 for the six months ended June 30, 2018:

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, January 1, 2018 | **6** |
| Realized losses included in revenue | **(7)** |
| Purchases | **40** |
| Closing balance, June 30, 2018 | **39** |

**Investments Measured at Net Asset Value**

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at June 30, 2018:

| *(millions of dollars except where noted)* | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice |
|---|---|---|---|---|
| Real Assets | | | | |
| Infrastructure | **1,452** | **751** | **n/a** | **n/a** |
| Real Estate | **1,034** | **535** | **n/a** | **n/a** |
| Agriculture | **119** | **78** | **n/a** | **n/a** |
| Pooled Funds | | | | |
| Short-term Investments | **29** | **n/a** | **Daily** | **1-5 days** |
| Fixed Income | **505** | **n/a** | **Daily** | **1-5 days** |
| Equity | **897** | **n/a** | **Daily** | **1-5 days** |
| Total | **4,036** | **1,364** | | |

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments in global farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each agriculture fund will be received

based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

## 13. SHARE CAPITAL

Common Shares

As at June 30, 2018 and December 31, 2017, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In March 2018 and December 2017, OPG issued 4,627,343 Class A shares at a price of $43.74 per share and 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injections in OPG, generating proceeds of $202 million and $519 million, respectively. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Fair Hydro Trust's acquisitions of Investment Interests from the IESO in March 2018 and December 2017 of $460 million and $1,179 million, respectively.

In April 2018, OPG issued 1,498,856 Class A shares at a price of $43.74 per share to the Province for its equity injection in OPG, generating proceeds of $66 million. The proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt representing 44 percent of the total funding requirements for the Trust's acquisition of Investment Interest from the IESO in April 2018 of $149 million.

As at June 30, 2018, OPG had 18,343,815 Class A shares issued and outstanding at a stated value of $787 million. (December 31, 2017 − 12,217,616 Class A shares issued and outstanding at a stated value of $519 million).

## 14. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding for three months ended June 30, 2018 was 274.3 million (three months ended June 30, 2017 – 256.3 million) and for the six months ended June 30, 2018 was 271.7 million (six months ended June 30 2017 – 256.3 million). There were no dilutive securities as at June 30, 2018 and June 30, 2017.

## 15. COMMITMENTS AND CONTINGENCIES

### Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from the Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

### Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at June 30, 2018, the total amount of guarantees OPG provided to these entities was $78 million (December 31, 2017 − $82 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at June 30, 2018, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

## Contractual and Commercial Commitments

OPG's contractual obligations as at June 30, 2018 are as follows:

| *(millions of dollars)* | **2018[1]** | **2019** | **2020** | **2021** | **2022** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Fuel supply agreements | 94 | 125 | 115 | 88 | 67 | 67 | 556 |
| Contributions to the OPG registered pension plan [2] | 107 | 219 | - | - | - | - | 326 |
| OPG long-term debt repayment | 71 | 368 | 663 | 413 | 172 | 4,771 | 6,458 |
| Interest on OPG long-term debt | 138 | 267 | 245 | 216 | 202 | 4,052 | 5,120 |
| Fair Hydro Trust senior debt repayment | - | 12 | - | - | - | 900 | 912 |
| Interest on Fair Hydro Trust senior debt | 15 | 31 | 31 | 31 | 31 | 410 | 549 |
| Commitments related to Darlington Refurbishment project [3] | 362 | - | - | - | - | - | 362 |
| Commitments related to Nanticoke Solar project | 45 | - | - | - | - | - | 45 |
| Commitments related to Ranney Falls GS project | 14 | 5 | - | - | - | - | 19 |
| Operating licences | 20 | 41 | 41 | 19 | 20 | 60 | 201 |
| Operating lease obligations | 14 | 26 | 25 | 22 | 22 | 78 | 187 |
| Unconditional purchase obligations | 27 | 54 | 52 | 4 | - | - | 137 |
| Accounts payable and accrued charges | 874 | - | - | - | - | 16 | 890 |
| Other | 46 | 42 | 3 | 1 | 2 | 63 | 157 |
| Total | 1,827 | 1,190 | 1,175 | 794 | 516 | 10,417 | 15,919 |

[1] Represents amounts for the remainder of the year.

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

## 16. BUSINESS SEGMENTS

| Segment (Loss) Income for the Three Months Ended June 30, 2018 *(millions of dollars)* | Regulated | | | Unregulated | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear Generation | Nuclear Waste Management | Hydro-electric | Contracted Generation Portfolio | Fair Hydro Trust | Other | Elimination | Total |
| Revenue from contracts with customers | 725 | - | 390 | 149 | - | 5 | - | 1,269 |
| Leasing revenue | 9 | - | - | - | - | 4 | - | 13 |
| Other revenue | - | 32 | - | - | - | 9 | (41) | - |
| Total revenue | 734 | 32 | 390 | 149 | - | 18 | (41) | 1,282 |
| Fuel expense | 62 | - | 90 | 14 | - | - | - | 166 |
| Gross margin | 672 | 32 | 300 | 135 | - | 18 | (41) | 1,116 |
| Operations, maintenance and administration | 620 | 32 | 82 | 43 | - | 7 | (41) | 743 |
| Depreciation and amortization | 130 | - | 40 | 19 | - | 9 | - | 198 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 244 | - | 2 | - | 1 | - | 247 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (212) | - | - | - | - | - | (212) |
| Earnings from Fair Hydro Trust | - | - | - | - | (8) | - | - | (8) |
| Income from investments subject to significant influence | - | - | - | (10) | - | - | - | (10) |
| Property taxes | 6 | - | - | 3 | - | - | - | 9 |
| Other losses | - | - | - | - | - | 5 | - | 5 |
| (Loss) income before interest and income taxes | (84) | (32) | 178 | 78 | 8 | (4) | - | 144 |
| Net interest expense | | | | | | | | 18 |
| **Income before income taxes** | | | | | | | | 126 |
| Income tax expense | | | | | | | | - |
| **Net income** | | | | | | | | 126 |

| **Segment (Loss) Income for the Three Months Ended June 30, 2017** *(millions of dollars)* | **Regulated** | | | **Unregulated** | | | | |
|---|---|---|---|---|---|---|---|---|
| | **Nuclear Generation** | **Nuclear Waste Management** | **Hydro-electric** | **Contracted Generation Portfolio** | **Fair Hydro Trust** | **Other** | **Elimination** | **Total** |
| Revenue from contracts with customers | 600 | - | 379 | 147 | - | 2 | - | 1,128 |
| Leasing revenue | 9 | - | - | - | - | 6 | - | 15 |
| Other revenue | - | 30 | - | - | - | 14 | (41) | 3 |
| Total revenue | 609 | 30 | 379 | 147 | - | 22 | (41) | 1,146 |
| Fuel expense | 68 | - | 97 | 13 | - | - | - | 178 |
| Gross margin | 541 | 30 | 282 | 134 | - | 22 | (41) | 968 |
| Operations, maintenance and administration | 593 | 32 | 75 | 40 | - | 12 | (41) | 711 |
| Depreciation and amortization | 110 | - | 35 | 20 | - | 7 | - | 172 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 232 | - | 2 | - | 2 | - | 236 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (194) | - | - | - | - | - | (194) |
| Income from investments subject to significant influence | - | - | - | (8) | - | - | - | (8) |
| Property taxes | 7 | - | - | 3 | - | 1 | - | 11 |
| Other gains | - | - | - | - | - | (380) | - | (380) |
| (Loss) income before interest and income taxes | (169) | (40) | 172 | 77 | - | 380 | - | 420 |
| Net interest expense | | | | | | | | 16 |
| **Income before income taxes** | | | | | | | | 404 |
| Income tax expense | | | | | | | | 97 |
| **Net income** | | | | | | | | 307 |

| Segment (Loss) Income for the Six Months Ended June 30, 2018 *(millions of dollars)* | Regulated | | | Unregulated | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear Generation | Nuclear Waste Management | Hydro-electric | Contracted Generation Portfolio | Fair Hydro Trust | Other | Elimination | Total |
| Revenue from contracts with customers | 1,596 | - | 746 | 298 | - | 15 | - | 2,655 |
| Leasing revenue | 18 | - | - | - | - | 8 | - | 26 |
| Other revenue | - | 65 | - | - | - | 28 | (85) | 8 |
| Total revenue | 1,614 | 65 | 746 | 298 | - | 51 | (85) | 2,689 |
| Fuel expense | 135 | - | 155 | 31 | - | - | - | 321 |
| Gross margin | 1,479 | 65 | 591 | 267 | - | 51 | (85) | 2,368 |
| Operations, maintenance and administration | 1,224 | 65 | 162 | 84 | - | 15 | (85) | 1,465 |
| Depreciation and amortization | 251 | - | 76 | 39 | - | 18 | - | 384 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 487 | - | 4 | - | 3 | - | 494 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (422) | - | - | - | - | - | (422) |
| Earnings from Fair Hydro Trust | - | - | - | - | (12) | - | - | (12) |
| Income from investments subject to significant influence | - | - | - | (20) | - | - | - | (20) |
| Property taxes | 13 | - | - | 4 | - | 1 | - | 18 |
| Other losses (gains) | - | - | 4 | - | - | (258) | - | (254) |
| (Loss) income before interest and income taxes | (9) | (65) | 349 | 156 | 12 | 272 | - | 715 |
| Net interest expense | | | | | | | | 37 |
| **Income before income taxes** | | | | | | | | 678 |
| Income tax expense | | | | | | | | 13 |
| **Net income** | | | | | | | | 665 |

| Segment (Loss) Income for the Six Months Ended June 30, 2017 *(millions of dollars)* | Regulated | | Unregulated | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Nuclear Generation | Nuclear Waste Management | Hydro-electric | Contracted Generation Portfolio | Fair Hydro Trust | Other | Elimination | Total |
| Revenue from contracts with customers | 1,243 | - | 742 | 290 | - | 4 | - | 2,279 |
| Leasing revenue | 18 | - | - | - | - | 20 | - | 38 |
| Other revenue | - | 57 | - | - | - | 27 | (79) | 5 |
| Total revenue | 1,261 | 57 | 742 | 290 | - | 51 | (79) | 2,322 |
| Fuel expense | 136 | - | 170 | 27 | - | - | - | 333 |
| Gross margin | 1,125 | 57 | 572 | 263 | - | 51 | (79) | 1,989 |
| Operations, maintenance and administration | 1,182 | 61 | 151 | 79 | - | 25 | (79) | 1,419 |
| Depreciation and amortization | 217 | - | 69 | 39 | - | 14 | - | 339 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 466 | - | 4 | - | 4 | - | 474 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (383) | - | - | - | - | - | (383) |
| Income from investments subject to significant influence | - | - | - | (18) | - | - | - | (18) |
| Property taxes | 13 | - | - | 5 | - | 4 | - | 22 |
| Other gains | - | - | - | - | - | (383) | - | (383) |
| (Loss) income before interest and income taxes | (287) | (87) | 352 | 154 | - | 387 | - | 519 |
| Net interest expense | | | | | | | | 35 |
| **Income before income taxes** | | | | | | | | 484 |
| Income tax expense | | | | | | | | 109 |
| **Net income** | | | | | | | | 375 |

The earnings from Fair Hydro Trust are comprised of the following for the three and six months ended June 30:

| *(millions of dollars)* | Three Months Ended June 30 2018 | 2017 | Six Months Ended June 30 2018 | 2017 |
|---|---|---|---|---|
| Revenue | **-** | - | **(1)** | - |
| Operating expenses | **-** | - | **1** | - |
| Interest income | **(17)** | - | **(27)** | - |
| Interest expense | **9** | - | **15** | - |
| Earnings from Fair Hydro Trust | **(8)** | - | **(12)** | - |

In December 2017, the Fair Hydro Trust was established as a separate entity to be the financing entity contemplated by the *Ontario Fair Hydro Plan Act, 2017*. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG, and the Trust's financial position and results are consolidated into OPG's financial results. As a legal matter, the assets and liabilities of the Trust do not form part of the assets and liabilities of OPG, and vice versa, pursuant to section 53.1(1.4) of the *Electricity Act, 1998* (Ontario).

OPG's fees for financial management and ongoing administration services provided to the Trust are subject to review by the OEB. In July 2018, the OEB approved OPG's proposed general fee for 2017 of approximately $6 million. The OEB also approved OPG's proposed benchmark interest rates for use in calculating a portion of the Company's fees for 2018 and for the first quarter of 2019.

## 17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

| *(millions of dollars)* | Six Months Ended June 30 2018 | 2017 |
|---|---|---|
| Receivables from related parties | **(37)** | 62 |
| Fuel inventory | **(3)** | 4 |
| Materials and supplies | **10** | 15 |
| Prepaid expenses | **9** | (11) |
| Other current assets [1] | **48** | 19 |
| Income taxes recoverable | **(97)** | (74) |
| Accounts payable and accrued charges | **(35)** | (140) |
| | **(105)** | (125) |

[1] Represents other accounts receivable.

## 18. PAYMENT OF DIVIDEND TO SHAREHOLDER

In April 2017, OPG completed the sale of its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in December 2015. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG was required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. In accordance with these requirements, a special dividend of $283 million was authorized by OPG's Board of Directors and transferred into the Consolidated Revenue Fund in March 2018.

## 19. SALE OF LAKEVIEW SITE

In March 2018, OPG completed the sale of its former Lakeview GS site property located in Mississauga, Ontario, with an after-tax gain on sale of $205 million, which is net of income tax effects of $68 million, recognized in net income in the first quarter of 2018. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution received by OPG in June 2016. Pursuant to the Shareholder Declaration and the Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund.

## 20. SUBSEQUENT EVENTS

On August 8, 2018, OPG entered into a purchase and sale agreement with Power Energy Eagle Creek, LLC and Hudson Clean Energy Partners LP to acquire 100 percent of the equity in Eagle Creek Renewable Energy LLC (Eagle Creek) for USD $298 million, subject to customary working capital and other adjustments. Eagle Creek is a hydropower platform, with 226 MW of capacity spread across 76 hydroelectric facilities and two solar facilities throughout the United States, and represents an opportunity to expand OPG's renewable generation portfolio to new geographies, with additional carbon-free generation aligning to OPG's strategic imperatives. The majority of facilities within Eagle Creek's fleet have operated as merchant based plants in the New England, Michigan and New York market areas. The acquisition of Eagle Creek is subject to receipt of final regulatory approvals, with closing expected to occur towards the end of 2018.

# OPG Qs and As

Nuclear Targets:

1. **Please explain why cost is not included as part of the nuclear refurbishment MTIP target.** (Note that the in service date for Unit 2 is the Execution Effectiveness goal for the 2017-2019 MTIP cycle. Number of fuel channels installed by the end of 2018 is the interim goal associated with the medium term performance measures for 2016-2018).

   **Response:**

   - It is very difficult to come in on time but over budget, as most of the remaining uncertain costs are schedule-driven and labour-related (engineering is complete and materials are already on order).
   - Appropriate cost will depend on scope, as OPG can move work pre or post milestone. This is why (as described below), the CEO and board will exercise judgement in determining success in relation to this metric.
   - OPG wanted a stand-alone measure to assess the progress of work on Darlington Refurbishment that was schedule / milestone oriented. The other two MTIP measures are largely financial oriented. The number of new fuel channels installed on the first unit of our key destiny project was viewed as an easy to understand and tangible measure for evaluation. The Board has an over ride ability on the milestone measures that looks at the achievement of the milestones per the RQE cost schedule. Cost relative to budget will be considered by the Board in assessing results. This ensures balance between the two. In addition, the Board has discretion to incorporate any factors they deem relevant when assessing performance. In addition to cost relative to budget, they could consider factors such as Safety, project quality environment, reputation or any other factor they felt was material.
   - We would prefer not to have an explicit cost component embedded in the goal for a couple of reasons:
     - The current treatment was the Board's preference
     - Over budget may be a favourable result for OPG and the province if the project was ahead of schedule.

**1b). Please explain how the STIP and MTIP targets interact.**

**Response:**

- The *Stakeholder Return Program* (SRP) establishes annual targets for key financial and operational measures. Performance is focussed both corporately and individually on achieving or exceeding Business Plan, and supporting initiatives that drive customer benefits. SRP goals are tied to the current year of the business plan.
- MTIP's medium-term targets drive sustained corporate performance over a longer period of time, and focus on increasing shareholder value. MTIP goals are tied to the longer term outlook in the business plan.
- Achievement of the annual SRP financial targets (e.g. EBT and OM&A) and project targets (Darlington Refurbishment Project (DRP) milestones) are annual indicators of progress towards achieving the longer term MTIP goals (Total Generation Cost, ROE and DRP in-service).

ROE and Capital Structure:

2. **Please provide a break-down of OPG's existing debt portfolio (maturities, interest rates). Please also denote all project debt, issued to private sector bondholders.**

**Response:**

Debt Maturity Schedule AS OF: 16-Nov-16

Summary - OPG Consolidated

| | Amount ($M) | Average Coupon | Average Term (yr) |
|---|---|---|---|
| Corporate (OEFC) | 3,405 | 4.9% | 6.1 |
| Project Finance (Private Sector) | | | |
| Lower Mattagami | 1,795 | 3.9% | 18.1 |
| Upper Mattagami | 184 | 7.6% | 24.5 |
| Peter Sutherland Sr. | 245 | 4.8% | 51.0 |
| Sub-Total Project Finance | 2,224 | 4.3% | 22.2 |
| Total - OPG Consolidated | 5,629 | 4.6% | 12.5 |

Details - Corporate (OEFC)

| Issue Date | Maturity Date | Amount ($M) | Coupon | Term (yrs) |
|---|---|---|---|---|
| 29-Dec-06 | 22-Dec-16 | 90 | 4.81% | 0.1 |
| 29-Dec-06 | 22-Dec-16 | 20 | 4.81% | 0.1 |
| 22-Jan-07 | 23-Jan-17 | 50 | 4.89% | 0.2 |
| 23-Apr-07 | 23-Apr-17 | 30 | 4.97% | 0.4 |
| 23-Apr-07 | 23-Apr-17 | 30 | 4.97% | 0.4 |
| 22-Jun-07 | 22-Jun-17 | 100 | 5.44% | 0.6 |
| 23-Jul-07 | 22-Jul-17 | 40 | 5.44% | 0.6 |
| 24-Sep-07 | 22-Sep-17 | 200 | 5.55% | 0.8 |
| 21-Dec-07 | 22-Sep-17 | 400 | 5.31% | 0.8 |
| 22-Oct-07 | 22-Oct-17 | 50 | 5.47% | 0.9 |
| 22-Jan-08 | 22-Jan-18 | 40 | 5.22% | 1.2 |
| 22-Jan-08 | 22-Jan-18 | 35 | 5.22% | 1.2 |
| 24-Mar-08 | 22-Mar-18 | 200 | 5.09% | 1.3 |
| 22-Apr-08 | 22-Apr-18 | 30 | 5.42% | 1.4 |
| 22-Apr-08 | 22-Apr-18 | 20 | 5.42% | 1.4 |
| 22-Jul-08 | 22-Jul-18 | 30 | 5.50% | 1.6 |
| 22-Jul-08 | 22-Jul-18 | 20 | 5.50% | 1.6 |
| 22-Oct-08 | 22-Oct-18 | 20 | 6.33% | 1.9 |
| 22-Jan-09 | 22-Jan-19 | 30 | 6.18% | 2.2 |
| 22-Jan-09 | 22-Jan-19 | 10 | 6.18% | 2.2 |
| 23-Mar-09 | 22-Mar-19 | 100 | 5.65% | 2.3 |
| 22-Apr-09 | 22-Apr-19 | 35 | 5.64% | 2.4 |
| 22-Apr-09 | 22-Apr-19 | 10 | 5.64% | 2.4 |
| 22-Apr-09 | 23-Apr-19 | 30 | 5.64% | 2.4 |
| 22-Jul-09 | 22-Jul-19 | 35 | 5.18% | 2.6 |
| 22-Jul-09 | 22-Jul-19 | 30 | 5.18% | 2.6 |
| 22-Oct-09 | 22-Oct-19 | 35 | 4.86% | 2.9 |
| 22-Oct-09 | 22-Oct-19 | 50 | 4.86% | 2.9 |
| 22-Jan-10 | 22-Jan-20 | 50 | 4.62% | 3.2 |
| 22-Mar-10 | 22-Mar-20 | 230 | 4.68% | 3.3 |
| 22-Apr-10 | 22-Apr-20 | 65 | 4.95% | 3.4 |
| 22-Jul-10 | 22-Jul-20 | 35 | 4.66% | 3.6 |
| 22-Sep-10 | 22-Sep-20 | 230 | 4.39% | 3.8 |
| 22-Oct-10 | 22-Oct-20 | 50 | 4.09% | 3.9 |
| 24-Jan-11 | 22-Jan-21 | 40 | 4.57% | 4.2 |
| 26-Apr-11 | 22-Apr-21 | 35 | 4.63% | 4.4 |
| 29-Jul-11 | 22-Jul-21 | 50 | 4.15% | 4.6 |
| 24-Oct-11 | 22-Oct-21 | 60 | 3.99% | 4.9 |
| 23-Jan-12 | 22-Jan-22 | 40 | 3.58% | 5.2 |
| 23-Apr-12 | 22-Apr-22 | 35 | 3.52% | 5.4 |
| 23-Jul-12 | 22-Jul-22 | 45 | 2.98% | 5.6 |
| 22-Oct-12 | 22-Oct-22 | 30 | 3.16% | 5.9 |
| 22-Jan-13 | 22-Jan-23 | 20 | 3.27% | 6.2 |
| 22-Apr-13 | 22-Apr-23 | 20 | 2.96% | 6.4 |
| 22-Nov-16 | 22-Nov-26 | 50 | 3.04% | 10.0 |
| 22-Mar-11 | 22-Mar-41 | 150 | 5.40% | 24.3 |
| 22-Sep-11 | 22-Sep-41 | 150 | 4.74% | 24.8 |
| 30-Apr-12 | 22-Mar-42 | 200 | 4.36% | 25.3 |
| 22-Nov-16 | 22-Nov-46 | 50 | 4.03% | 30.0 |
| Total - Corporate (OEFC) | | 3,405 | 4.87% | 6.1 |

Details - Project Financing

| Project | Issue Date | Maturity Date | Amount ($M | Coupon | Term (yrs) |
|---|---|---|---|---|---|
| Lower Mattagami (LM) | | | | | |
| | 23-Oct-12 | 23-Oct-17 | 200 | 2.23% | 0.9 |
| | 17-May-11 | 18-May-21 | 225 | 4.33% | 4.5 |
| | 20-Jun-14 | 20-Jun-24 | 200 | 3.42% | 7.6 |
| | 7-Oct-16 | 21-Oct-26 | 220 | 2.31% | 9.9 |
| | 17-May-11 | 18-May-41 | 250 | 5.14% | 24.5 |
| | 20-Sep-13 | 21-Sep-43 | 200 | 4.94% | 26.9 |
| | 25-Feb-13 | 23-Feb-46 | 275 | 4.18% | 29.3 |
| | 23-Apr-12 | 23-Apr-52 | 225 | 4.18% | 35.5 |
| **Subtotal-LM** | | | **1,795** | **3.88%** | **18.1** |
| | | | | | |
| **Upper Mattagami (UM)** | 8-May-09 | 8-May-41 | **184** | **7.59%** | **24.5** |
| | | | | | |
| **Peter Sutherland Sr. (PSS)** | 20-Oct-15 | 24-Oct-67 | **245** | **4.80%** | **51.0** |
| | | | | | |
| **Total-Project Financing ($M)** | | | **2,224** | **4.29%** | **22.2** |

1. LM bonds are bullet bonds, i.e. the full amount of principal will be paid off at maturity

2. UM and PSS bonds are amortizing bonds, i.e. a portion of of the bonds principal will be amortized and paid off prior to maturity

3. For UM bond, ~40% of bond principal will be paid off prior to maturity, with ~60% principal amount remaining at maturity

4. For PSS bond, 80% of bond principal will be paid off prior to maturity, with 20% principal remaining at maturity

**3. Has there been an increase in long term borrowing from OEFC?**

- Current agreements with the OEFC limit long term debt to 50% of any draw amount with the remaining balance being 10 yr term or shorter.
- For the latest draw on November 22, 2016 a request was put forth to the OEFC to increase the percentage of 30 yr debt, which was turned down. Consequently, OPG exercised the right to have 50% of the draw amount at 30 yrs with the remaining balance at 10 yrs.

**4.** Given the current interest rate environment, would it be helpful to increase the average term for OEFC debt?

- Yes, we have already identified that as an objective and a benefit in our discussions and presentations especially given the $900M OEFC debt maturing in 2017 and the anticipated overall increase in borrowing requirements. Long term debt locked-in at low rates will minimize the refinancing risk to the benefit of rate payers. Furthermore, the public debt markets currently have the capacity to provide terms beyond 30 yrs which are not available through the OEFC.

**5. What is OPG's target capital structure? What is OPG's existing capital structure and what is the path to target capital structure?**

**Response:**

- OPG's existing capital structure is composed of about 35% debt and 65% equity.
- OPG considered an option to "Immediately" move to target capital by way of an increase in debt and a corresponding payment of a dividend to decrease equity.
- However this path is expected to result in a credit rating downgrade as credit metrics are negatively affected and don't satisfy the rating agency guidelines.
- OPG plans to use a gradual managed transition from the existing capital structure to the target capital structure over a 10 year period which is expected to have no impact on the credit rating. The leverage program put in place would be in accordance with the following:
  - Establish a dividend program, to commence in 2017/18,
  - Monitor impact of higher debt on credit metrics to maintain credit rating;
  - Gradual / staged implementation to be tied to key business outcomes, in

particular, OEB regulated rate case and success on Darlington Unit 2 Refurbishment, in order to assess the impact of higher debt on financial results and credit metrics.

- The dividend program should be accompanied by the external debt platform, providing an independent source of funding that will drive discipline to dividend levels.
- This approach will provide more optionality as the increased leverage can fund dividend payments to Shareholder and/or fund growth opportunities

**6. Please show OPG's ROE targets using a deemed capital structure.**
**Response:**

- The ROE targets for the current business plan are shown in the table below as well as ROE targets under two additional scenarios:
  1) **Immediate** Increase in leverage to the deemed capital structure at the start of 2017, and
  2) **A gradual managed** transition to the deemed capital structure.
- Scenario 1 "Immediate Leverage" does not reflect the cost impact of a credit rating downgrade which is the expected result of this approach. Interest cost for new debt issued would be higher.
- In Scenario 2 "Gradual Managed Leverage" with no credit rating downgrade, the positive impact on ROE will become more pronounced in later years when i) leverage gradually moves up to be consistent with deemed capital structure. The 51% debt level will be achieved in 2025 post Darlington Refurb.

| | | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
|---|---|---|---|---|---|---|---|
| **Business Plan** | Debt Ratio | 34% | 37% | 36% | 35% | 33% | 31% |
| **November Board** | ROE target | 4.2 | 4.8 | 6.0 | 6.1 | 6.9 | 7.3 |
| **Leverage to 51%** | Debt Ratio | 34% | 51% | 51% | 51% | 51% | 51% |
| **Upfront** | ROE target | 4.2 | 5.7 | 6.8 | 7.0 | 8.2 | 8.9 |
| **Leverage to 51%** | Debt Ratio | 34% | 39% | 40% | 42% | 42% | 41% |
| **(No Acquisitions)** | ROE target | 4.2 | 4.9 | 6.1 | 6.3 | 7.4 | 8.0 |

**7. Please explain why ROE is preferable to net income or a cash target (FCFE, FFO etc.).**
**Response:**

- ROE is a preferable measure as it not only incorporates the impact of net income (numerator) but it also incorporates the impact of other management initiatives; i.e. the financing strategy and dividend program (denominator). As a return based measure on the shareholder's investment, ROE carries more meaning than a quantity of Net Income that is hard to evaluate or understand without relation to the investment made.

- ROE is a preferable measure to a cash target partly as a result of OPG's nuclear rate smoothing proposal. In accordance with US GAAP, rate smoothing deferrals in a given period will be recorded in revenue and income of the period. Cash collection of the deferred amounts will occur in the future after the Darlington Refurbishment is complete. Thus cash targets do not completely reflect OPG's financial performance in the short to medium term.

**8. Why there are flat years (2018 / 2019) in the ROE target?**
**Response:**

- To understand trend, it's important to see the change in income between 2017 and 2018 that gives rise to that delta in ROE and then between 2019 and 2020:

| NI & ROE | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Net Income ($M) | 438 | 508 | 679 | 729 | 883 | 1,004 |
| ROE (%) | 4.2 | 4.8 | 6.0 | 6.1 | 6.9 | 7.3 |

- 2018 Net Income is significantly higher than 2017 due to lower corporate level charges, higher interest capitalized related to Darlington Refurbishment and significantly higher hydroelectric production, compared to 2017 (0.9 TWh). The higher hydroelectric production in 2018 is related to less outages at Decew and Sir Adam Beck (SAB), including Hydro One related outages, compared to what occurred in 2017. As a result, 2018 Net Income increases at a higher rate than in 2019.
- In 2020, the increase in ROE from 2019 is driven from the in-service of Darlington U2 post refurbishment and the increase in income from ~ $4.8 billion entering the rate base in early 2020.
- There is a moderate increase in income between 2018 and 2019 and therefore a small increase in ROE resulting in a "flat" profile from 2018 to 2019.

**9. Please show annual ROEs for the past three years.**
**Response:**

- Annual ROE – measured over a 12-month period
  - 2015 – ROE = 4.0%, ROE excluding impact of extraordinary gain in 2014 = 4.1%
  - 2014 – ROE = 8.5%, ROE excluding impact of extraordinary gain in 2014 = 6.0%
  - 2013 – ROE = 1.5%
- The sharp increase in 2014 was in part due to the extraordinary gain realized in 2014 with the regulation of previously unregulated hydroelectric assets. Excluding that extraordinary gain, 2014 also had extremely cold winter weather resulting in very high trading margins and very high HOEP prices that helped our unregulated hydro operations in the first half of the year.

Total Cost of Generation:

10. **Please provide more detail on the methodology for calculating Total Cost of Generation. Why is this measure selected over other measures of efficiency?**
**Response:**

- **Total Generating Cost ($)** = OM&A expenses from ongoing operations + fuel and Gross Revenue Charge expenses for OPG-operated stations + sustaining capital expenditures
- **Production (MWh)** = OPG production + Surplus Baseload Generation
- **Total Generating Cost ($/MWh)** = Total Generating Cost ($) / Production (MWh)
- Total Generating Cost is a preferred measure of efficiency because it is the metric employed currently within our nuclear business, it is a metric that is benchmarked by the Electric Utility Cost Group (EUCG) and widely accepted for nuclear benchmarking, and takes into account all sustaining investments, be they capital or OM&A and therefore avoids capitalization differences between companies. OPG believes the TGC metric provides for a stronger incentive focus on consumer price than other alternatives as it represents OPG's all in cost to deliver a unit of net electrical production.

11. **As TCG is an industry-wide metric, is there a way in which OPG facilities can be fairly compared to competitors (I understand that this is likely not possible at the corporate level, but is there merit in comparisons at the plant or fleet level)?**
**Response:**

- In addition to Enterprise TGC (which is the efficiency metric used in the MTIP), OPG also maintains fleet- wide TGC's for both the Nuclear and Hydroelectric facilities. These can be found in Appendix 3 of the 2017-2019 Business Plan.

| Total Generation Cost | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 |
| Nuclear Total Generating Cost ($/MWh) | 63.2 | 75.8 | 74.6 | 74.5 | 77.1 | 77.3 |
| Hydroelectric Total Generating Cost ($/MWh) | 25.1 | 26.4 | 30.1 | 30.3 | 30.0 | 29.0 |
| Enterprise Total Generating Cost ($/MWh) | 48.4 | 54.7 | 55.6 | 55.7 | 56.8 | 56.0 |

- We believe that TGC is the best efficiency measure for our operating fleet. It reflects both cost to produce energy and the amount of energy produced. The EUCG uses a variety of measures including OMA cost per unit, TGC and contribution margin. We selected TGC at the group level to reflect the investment decisions both in terms of OM&A and sustaining capital across the entire fleet to maximize the generation capability of the fleet. We do not believe it is beneficial to split this measure when our asset planning is run on a fleet basis. Further splitting the measurement also has the impact of resulting in increased bureaucracy in the organization providing no value to the business decision making.

- Further sub-division of the TGC metric into the contracted segment is not feasible as plant level operations in RGPM are managed at a regional level. Furthermore, some regions have both regulated and contracted plants. It is also not how those regional centres are managed in terms of resources and operations.
- As indicated, for the nuclear plants, the most comprehensive cost benchmark is the EUCG and TGC is one of several benchmark metrics that are used. The TGC measure is provided as part of the benchmarking input OPG provides into the EUCG.

**12. Are there Electricity Utility Cost Group (EUCG) reports that OPG can share in order to contextualize / benchmark OPG's nuclear / hydro costs?**

- Both were shared with the Province. We will determine a way to synthesize results, and allow for an effective go-forward comparison.

**13. Given that generation is a key driver of this metric, please explain whether and how growth is built into the plan**

- **Organic growth at existing facilities**
- **New procurements (Ontario / other jurisdictions)**
- **Acquisitions**

**Response:**

- Organic growth at existing facilities that is in the business plan capital program is factored into the calculation. There is no other generation growth via acquisitions factored in the plan or calculation. Any incremental growth in generation would also carry with it any incremental costs in the TGC calculation, as applicable:
  - Organic Growth at Existing Facilities –Generation development projects can be found in the 2017-2019 Business Plan under Appendix 3 in the Capital Expenditure table.

| CAPEX | Forecast | Business Plan | | | Projection | |
|---|---|---|---|---|---|---|
| **Generation Dev. Projects** | **2016** | **2017** | **2018** | **2019** | **2020** | **2021** |
| Hydroelectric Development ($M) | 164 | 81 | 51 | 115 | 63 | 18 |
| Darlington Refurbishment ($M) | 1,037 | 1,152 | 1,113 | 1,111 | 1,045 | 1,061 |
| Nanticoke Solar Project ($M) | 1 | 5 | 95 | - | - | - |
| **Total Generation Dev.** | **1,202** | **1,239** | **1,259** | **1,236** | **1,107** | **1,079** |

  - Once these projects have been placed into service, these facilities (along with their associated operating costs and generation forecasts) have been included in the TGC calculation. As an example, any capacity changes such as runner upgrades in hydroelectric would be reflected in the sustaining capital costs to upgrade and the generation from the unit post upgrade. Also, new development projects within our existing infrastructure such as the Peter Sutherland Sr. hydroelectric project would form part of the TGC calculation once it is fully operational and in- service. The TGC calculation excludes all initial development

capital so as not to skew results but sustaining capital for our facilities is included.

- New Procurements/Acquisitions – New procurement/acquisitions are not built into the 2017- 2019 Business Plan that is the basis of the 2017-2019 MTIP.

**14. What is the status of Nanticoke Solar?**

- Development of the Nanticoke Solar Project is advancing well, and on schedule. All on-site environmental studies have been completed, including waterbody assessments, wetland evaluations, species-at-risk studies, natural heritage mapping, and archaeological surveys. Detailed boundary and topographical surveys have also been prepared, and all of the final environmental reports, including a stormwater management plan and grading plan, have been completed.
- Our partner and part-owner Six Nations Of The Grand River First Nation remains involved and supportive of the project as we progress through a more advanced stage of development. Electrical designs are well underway and we are in the process of contracting for structural post installation, testing, and engineering services; that work will commence on site very shortly. Final REA reports are being reviewed by Haldimand County, local First Nations and the local community. The final community engagement meeting is scheduled for February 2, 2017, and we will be submitting the complete REA package to the MOECC February 2017.
- OPG is in advanced discussions with partner SunEdison regarding the purchase by OPG of SunEdison's 25% interest in the Nanticoke Solar project. SunEdison Canadian Construction LP filed for CCAA protection with the Ontario Superior Court October 27th; however, this does not affect development of the project, nor OPG's ability to continue to achieve key project development milestones.

**15. Please consider removing from OPG's "Mission" the replacement of Pickering capacity from the business plan as this is a separate policy discussion. (Although I have not discussed this internally, I would suggest it may make sense to work together, separate from the business plan process on 1) a set of policy options for OPG growth that the Province can consider and 2) a process roadmap and set of criteria in order for the Province to consider specific acquisitions)**

**16. Please show annual TCG for the past three years at corporate and fleet level.**
**Response:**

- OPG Enterprise TGC – Actuals
  - 2015 – TGC/MWh = 50.89
  - 2014 – TGC/MWh = 46.44
  - 2013 – TGC/MWh = 49.88
- Fleet level measures are not available for the defined TGC measure on a historical level.

Pensions:

**17. Please confirm that Jeff and Ed were discussing the early revaluation of OPG's pension liabilities. If so, please provide details.**

**Response:**

- The actuarial valuation as at January 1, 2016 was filed September 30, 2016 within the prescribed regulatory period. Due to the current volatility in the markets, OPG chose to file its pension plan valuation as of January 1, 2016 because there was a significant benefit to the company to lock in contributions for 2016 at a level below the current Business Plan and mitigate the material risk of higher contributions in 2017 and 2018
- Based on capital markets returns and decrease in long term bond rates year-to-date, it is likely that a 2017 valuation would have resulted in higher minimum contributions than the 2016 valuation
- 2016 contributions to the pension plan over the next three year period are expected to be approximately $200M lower, with this benefit flowing to the rate payer.

**18. As it pertains to compensation, Korn Ferry Hay Group apparently also has follow ups OPG:**

**19. How does OPG use and justify the use of gold companies as acceptable peers?**

**Response:**

- The private sector utilities comparator group includes comparable utility organizations, but also includes other capital intensive industries (including mining and oil & gas) that have roles with comparable skills and experiences (i.e., construction / engineering / technical). This expanded group was also developed to ensure sufficient data to report meaningful statistics and to include organizations headquartered in central and eastern Canada to balance out the influence of Alberta-headquartered utility organizations.
- OPG positions are only benchmarked against comparable positions that can be matched in the peer organizations. Due to confidentiality issues, Willis Towers Watson is not able to specifically comment on the exact positions from the gold mining companies that were used in the analysis, but they can confirm that they only included roles that were comparable to an existing OPG role.

**19 b. What are the peers for the top 5 positions how are those justified?**

**Response:**

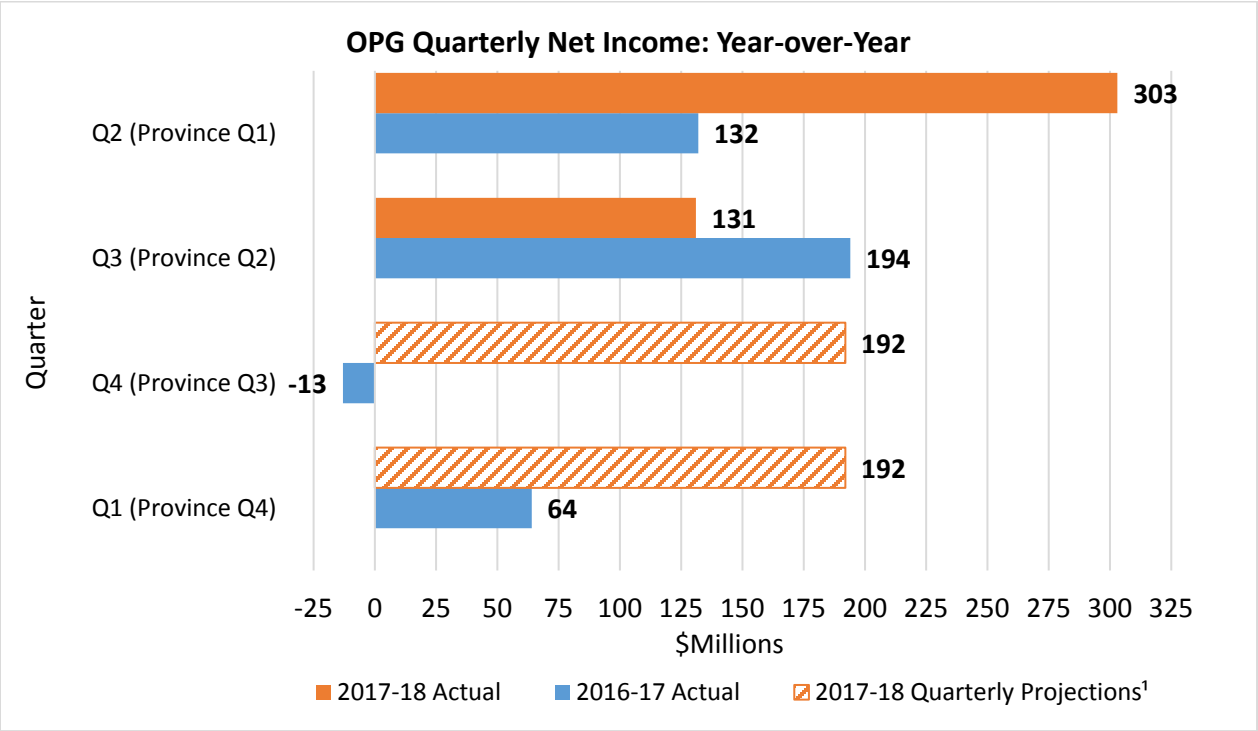
- Competitive compensation data for each of the top five executive positions reflects its appropriate segment (i.e. President, Authorized Nuclear, Utility or General Industry), as defined by the role requirements and using the same criteria as for other OPG roles. The top five executives can be found in Bands A, B, and C of the compensation structure:
    - The President & CEO has its own segment and comparator group, reflecting the complexity and scope of the role.
    - The CFO is in the general industry segment
    - The only executive among the top five to use the private sector utilities comparator group is the President, Renewable Generation and this role was matched to a “Division President” benchmark among these organizations (responsible for the operations / oversight of an independent division /

business unit).

- The other most highly compensated officers are all in the Authorized nuclear segment.

# OPG QUARTERLY UPDATE – Q3 of 2017 (draft)

## THIRD QUARTER 2017 RESULTS (FOR THREE MONTHS ENDED SEP. 30, 2017)




1. 2017-18 Quarterly projections are based on OPG's current year-end net income projection.

Net income attributable to the Shareholder was **$131 million**, a decrease of $63 million (-32.5%) compared to Q3 in 2016.

Significant Factors that **Reduced** Net Income:

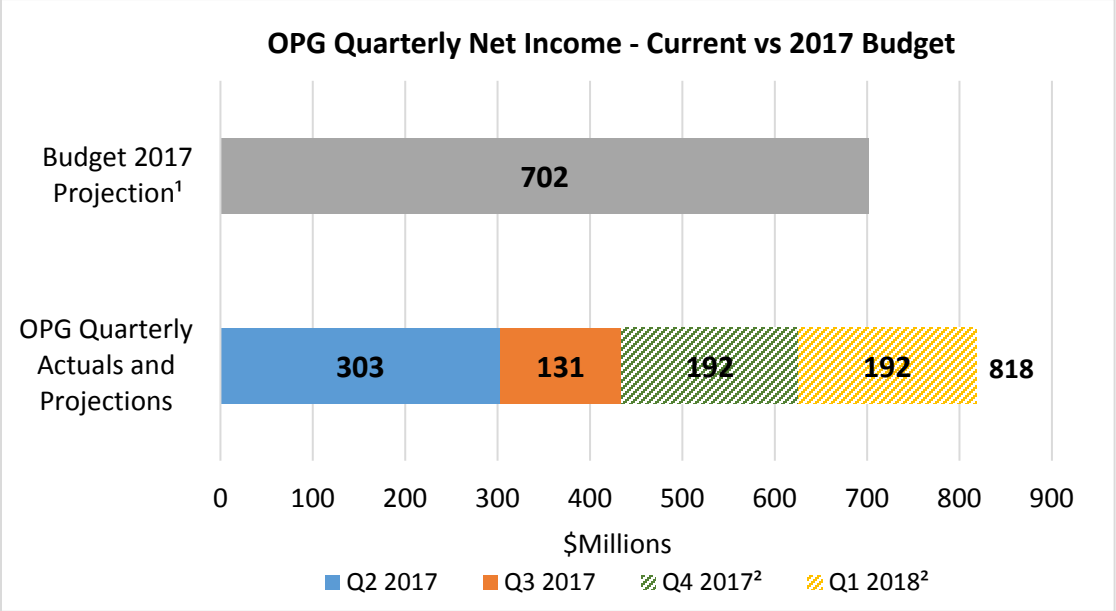
- Lower earnings resulting from
  - lower electricity generation (due to the ongoing refurbishment of Unit 2 at the Darlington GS) from the Regulated – Nuclear Generation segment
  - Continuation of existing base regulated prices set by the OEB in 2014, which continue to be in effect pending the OEB's decision on OPG's current application, expected later in 2017.
  - Lower earnings were offset by an increase in generation from Pickering GS due to outage optimization, favourable unit conditions and execution of planned outage work.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds – Nuclear Segregated Funds
- Higher depreciation and amortization expense in the Regulated – Nuclear Generation segment, primarily due to new assets in service. (Note: This excludes amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts – regulatory accounts)

Significant Factors that **Increased** Net Income:

- Lower OM&A expenses mainly in the
  - Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized

- Services, Trading and Other Non-Generation segment due to project expenditures incurred
- Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

## YEAR-TO-DATE NET INCOME SUMMARY NOTE




1. This number is not the adjusted net income value which takes into account of 'Extraordinary Gains', 'GA-OPG Trust Interest Revenue', and 'OPG IFRS consolidation risk picked up in Fiscal Plan'.
2. 2017-18 Quarterly projections are based on OPG's current year-end net income projection.

- OPG is currently projecting Net Income Attributable to Shareholders for 2017-18 to be $818 million, or $116 million above projections at the time of the 2017 Budget
- The increase is largely due to the higher gain on sale of OPG's head office from Q2 and lower OM&A expenses from Q3.
- As of Sep. 30, 2017, the total Net Income Attributable to Shareholders is $434 million (sum of Q2 and Q3 net income)
- Based on OPG's current fiscal year projections, an additional $384 million in net income is projected to be earned over Q4 2017 and Q1 2018.

## GENERATION DEVELOPMENT PROJECT UPDATES

| Project | Important Updates |
|---|---|
| Darlington Refurbishment | • Overall project continues to track on schedule and on budget<br>• The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017<br>• Re-tube Waste Processing Building became available for use in November 2017<br>• 17 out of 18 pre-requisite projects supporting refurbishment have been completed<br>• OPG is continuing planning activities for refurbishment of the second unit, Unit 3, and as of Sep. 30, 2017 $70 million have been invested in these activities. |
| Ranney Falls Hydroelectric GS | • Project is tracking on schedule and on budget<br>• Expected in-service date to be fourth quarter of 2019 |
| Nanticoke Solar Facility | • During third quarter of 2017, continued to obtain approvals and permits required for commencement of construction, and progressed procurement activities for equipment and engineering services<br>• Expected to be completed in first quarter of 2019 |

## FINANCING ACTIVITIES

| As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year. | |
|---|---|
| Relevant to OEFC | • In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017.<br>• In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.<br>• In addition to past issues of senior notes payable to the OEFC under this credit facility the following financing activities occurred in the third quarter:<br>o In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86%.<br>o In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07%<br>o As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility. |
| Relevant to Fair Hydro Plan | • In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program.<br>• The notes bear a coupon interest rate of 3.32% and an effective rate of 3.43%, payable semi-annually until maturity on October 4, 2027.<br>• The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.<br>• The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan. |

## Additional Important Information

**Ontario's Fair Hydro Plan**

- OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan. Accordingly, the financing entity was established as the Fair Hydro Trust (the Trust) and the majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG.
- Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017.
- In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG.
- The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations.
- The following developments have transpired:
    - In October 2017, Ontario Regulation 206/17 General was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust.
    - A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44% of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
    - OPG is expected to provide 5% of the total funding requirement of the Trust related to the deferred Global Adjustment costs. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust.
    - The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017

**Recovery of Pension and OPEB Costs (Regulatory Risk Factor)**

- On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors.
- The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval.
- The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset.
- OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

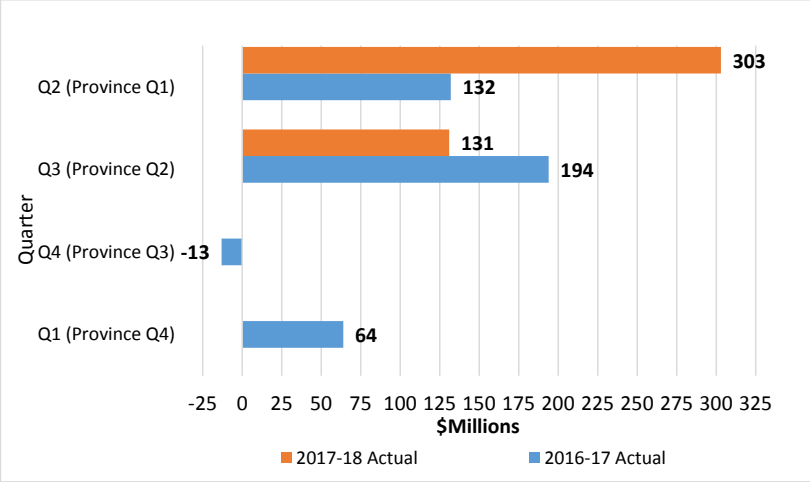
**Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS**

- On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report and gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory".
- The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

# ONTARIO POWER GENERATION INC.: ~~PG~~ Third Quarter Update~~QUARTERLY UPDATE – Q3 of 2017 (draft)~~

## YEAR-OVER-YEAR CHANGES

### OPG ~~THIRD QUARTER 2017 RESULTS (FOR THREE MONTHS ENDED SEP. 30, 2017)~~Quarterly Net Income to Shareholder: Year-over-year Changes




1. 2017-18 Quarterly projections are based on OPG's current year-end net income projection.

### Third Quarter: Year-over-year changes

Net income attributable to the Shareholder was $131 million, a decrease of $63 million (-32.5%) compared to Q3 in 2016.

**Significant Factors that Reduced Net Income~~:~~**

- Lower earnings resulting from
  - lower electricity generation (due to the ongoing refurbishment of Unit 2 at the Darlington GS) from the Regulated – Nuclear Generation segment
  - Continuation of existing base regulated prices set by the OEB in 2014, which continue to be in effect pending the OEB's decision on OPG's current application, expected later in 2017.
  - Lower earnings were offset by an increase in generation from Pickering GS due to outage optimization, favourable unit conditions and execution of planned outage work.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds – Nuclear Segregated Funds
- Higher depreciation and amortization expense in the Regulated – Nuclear Generation segment, primarily due to new assets in service. (Note: This excludes amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts – regulatory accounts)



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**Significant Factors that Increased Net Income~~:~~**

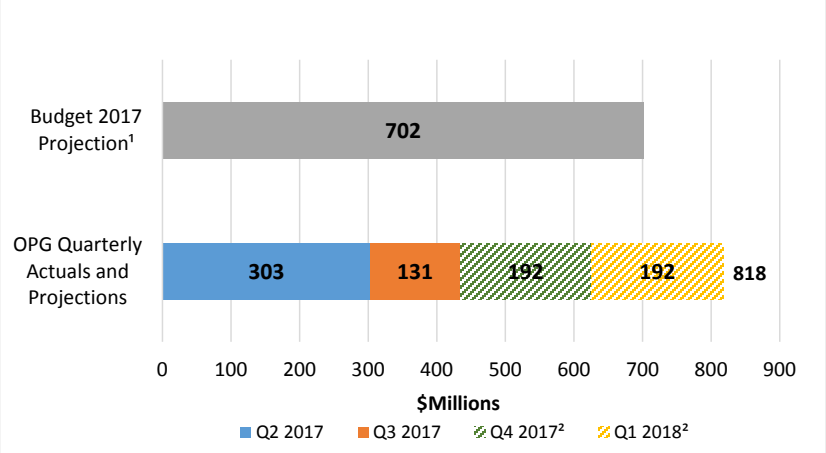
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  - Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized
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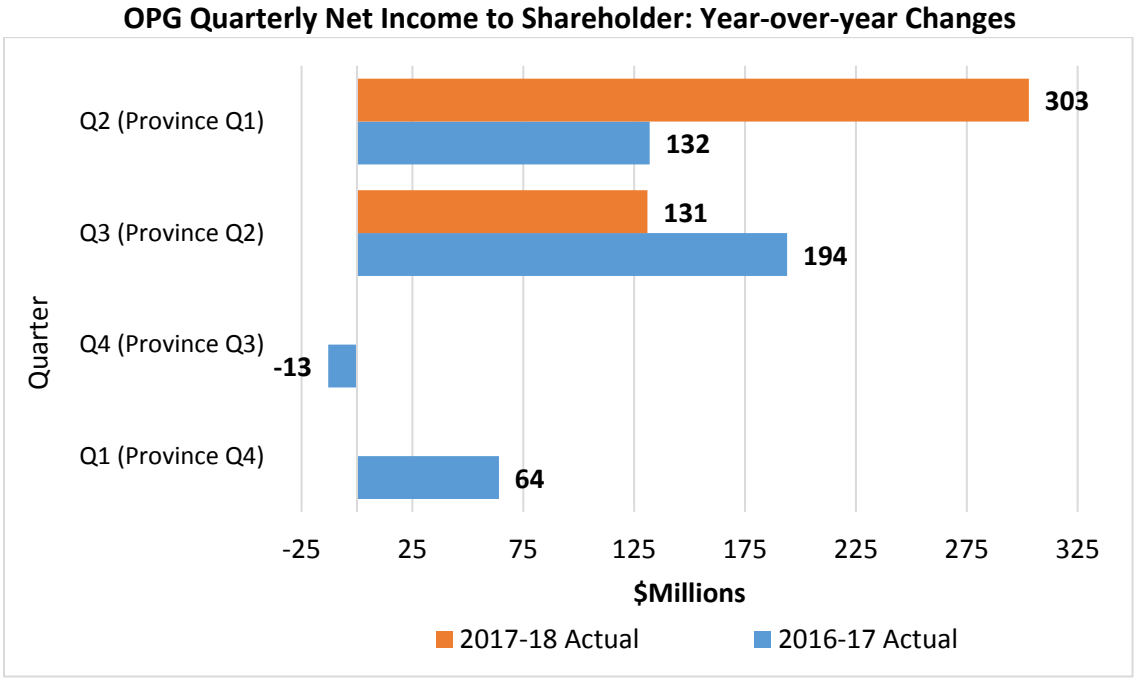
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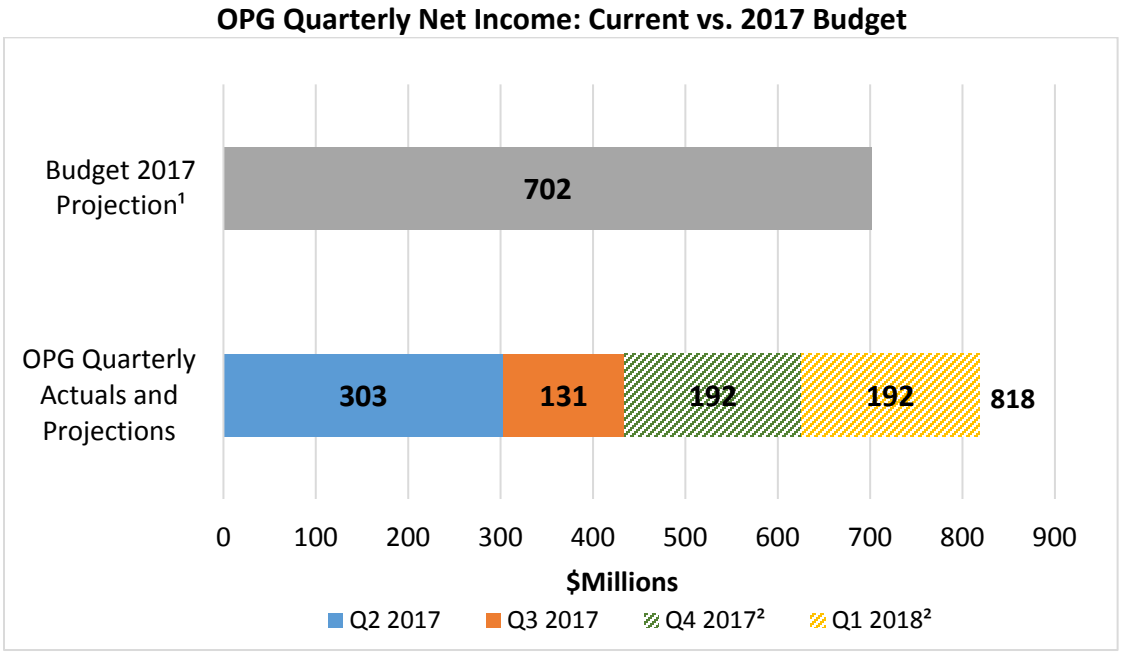
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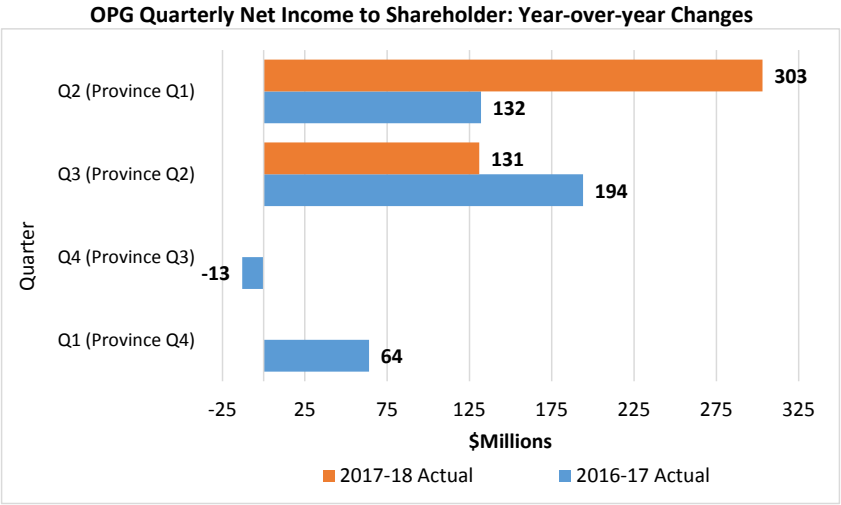
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**Electricity Finance Branch**
**November 2017**

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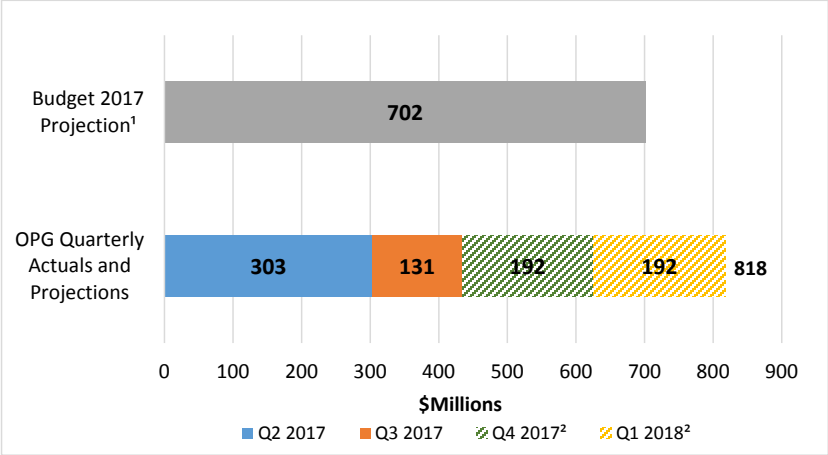
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**Commented [BA1]:** But combined q2 and q3? I think depr. and amortization is bigger factor?

Note urgent, but I may be a good idea to start a data base tracking the income statement by quarter to help with this analysis. We can get Mohamed to help with that.

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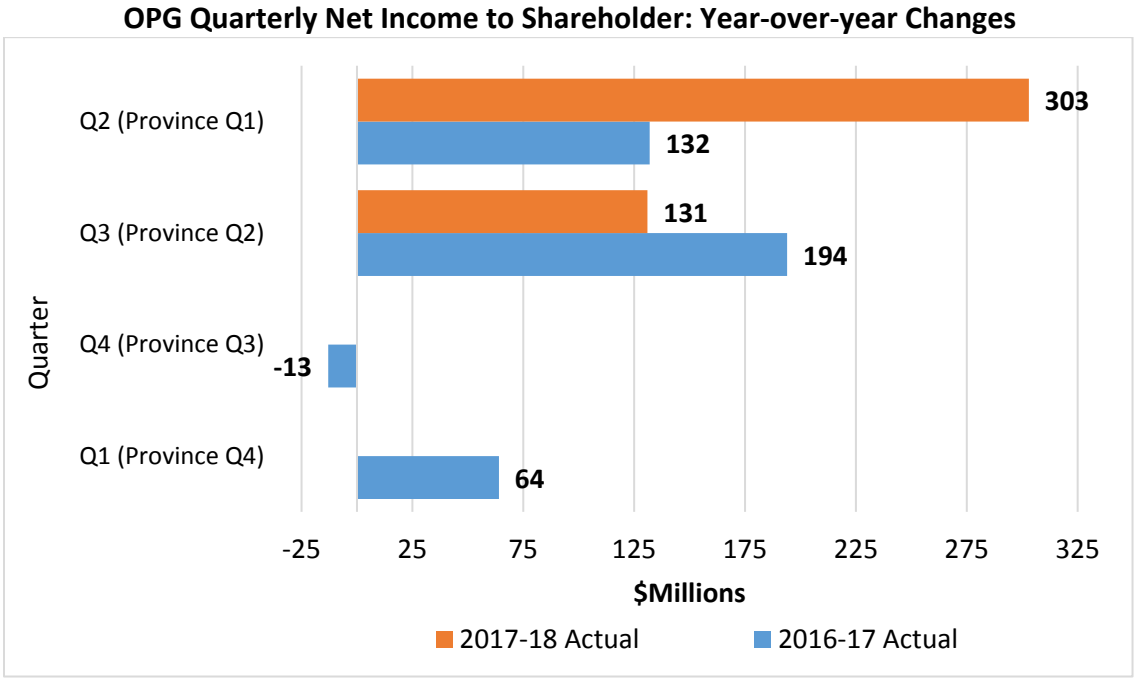
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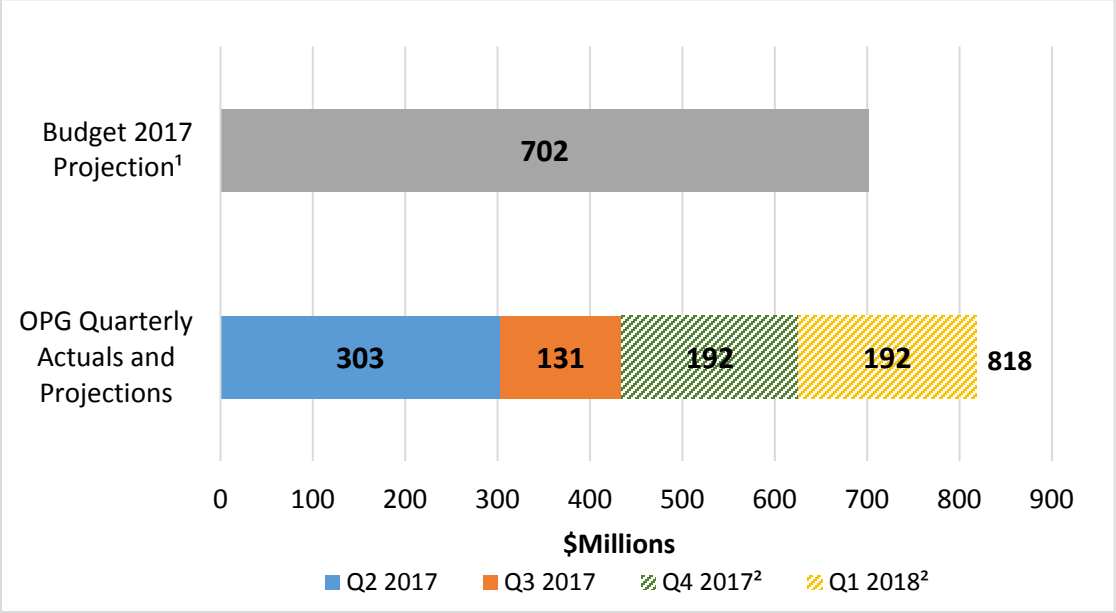
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| Relevant to Fair Hydro Plan | • In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program.<br>• The notes bear a coupon interest rate of 3.32% and an effective rate of 3.43%, payable semi-annually until maturity on October 4, 2027.<br>• The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017.<br>• The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan. |

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- The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset.
- OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

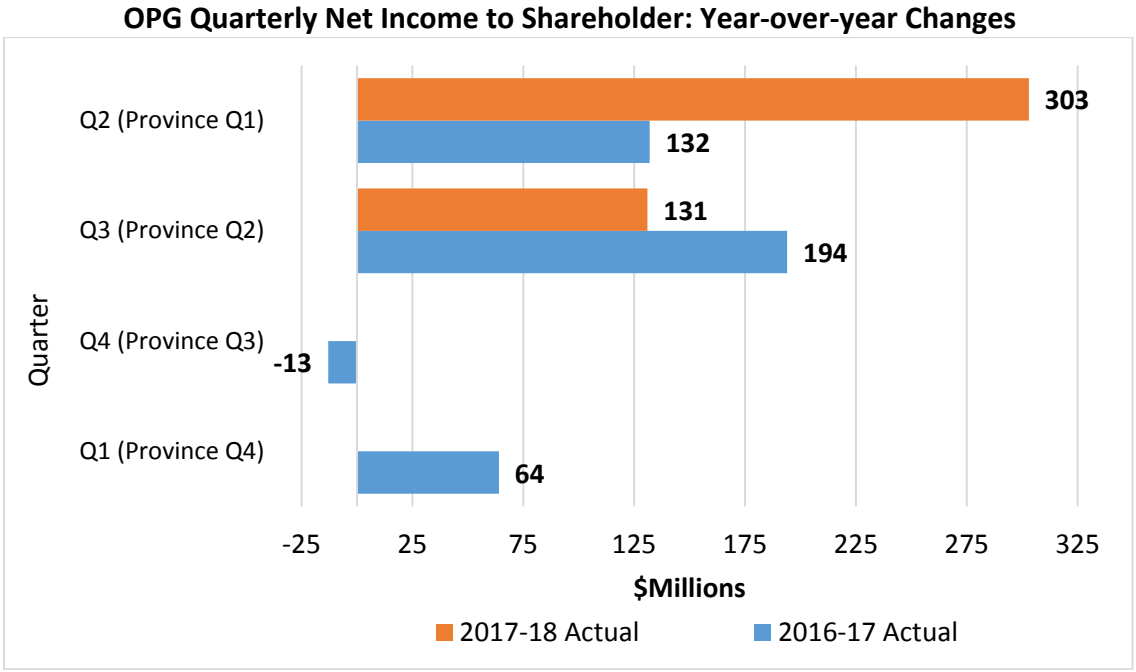
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**Electricity Finance Branch, November 2017**

# ONTARIO POWER GENERATION INC: Third Quarter Update

## YEAR-OVER-YEAR CHANGES




## THIRD QUARTER (PROVINCE Q2): YEAR-OVER-YEAR CHANGES

Net income attributable to the Shareholder in OPG's third quarter was $131 million, a decrease of $63 million (-32.5%) compared to the third quarter of 2016.

SIGNIFICANT FACTORS THAT REDUCED NET INCOME

- Lower earnings resulting from
  - lower electricity generation (due to the ongoing refurbishment of Unit 2 at the Darlington GS) from the Regulated – Nuclear Generation segment
  - Continuation of existing base regulated prices set by the OEB in 2014, which continue to be in effect pending the OEB's decision on OPG's current application, expected later in 2017.
  - Lower earnings were offset by an increase in generation from Pickering GS due to outage optimization, favourable unit conditions and execution of planned outage work.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds – Nuclear Segregated Funds
- Higher depreciation and amortization expense in the Regulated – Nuclear Generation segment, primarily due to new assets in service. (Note: This excludes amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts – regulatory accounts)

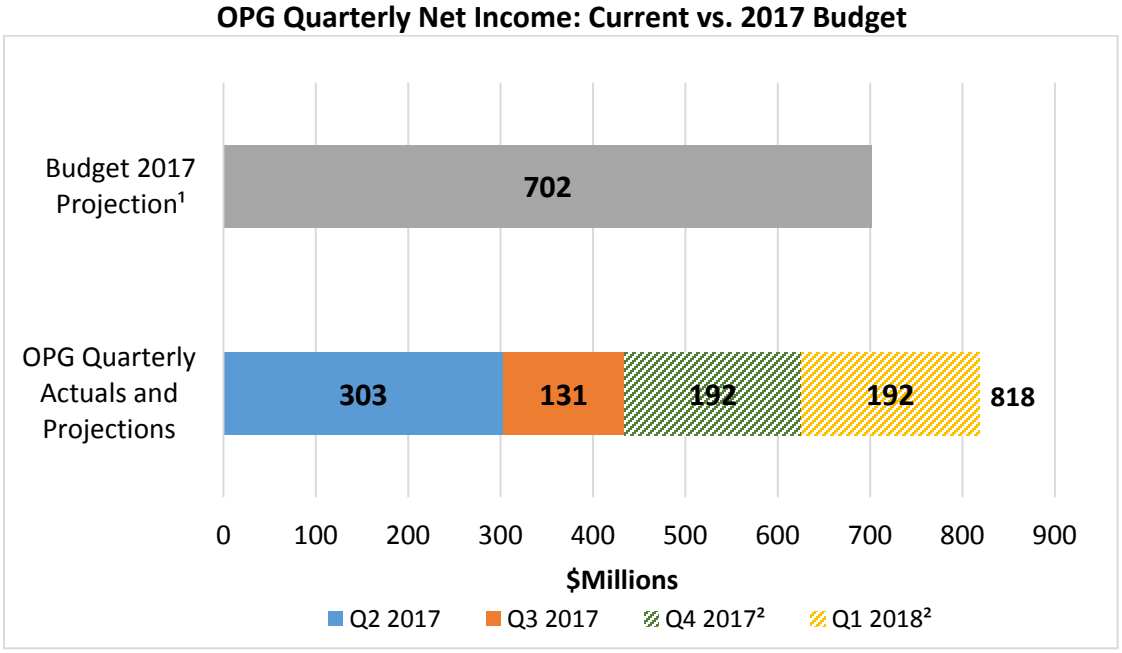
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## PROVINCIAL FISCAL YEAR-TO-DATE: YEAR-OVER-YEAR CHANGES

- OPG net income increased by $108 million in the second and third quarters (first half of province's fiscal year) compared to the same period a year ago.
- The increase was due largely to the second quarter gain on sale from OPG's head office and parking facilities. The same factors discussed above which contributed to lower third quarter earnings compared to a year ago also lowered earnings in the second quarter compared to a year ago.

## OPG CURRENT OUTLOOK VS. 2017 BUDGET




1. This number is not the adjusted net income value which takes into account of 'Extraordinary Gains', 'GA-OPG Trust Interest Revenue', and 'OPG IFRS consolidation risk picked up in Fiscal Plan'.
2. 2017-18 Quarterly projections for Q4 2017 and Q1 2018 are based on Q2 2017 and Q3 2017 actuals and OPG's current year-end net income projection.

- OPG is currently projecting 2017-18 net income attributable to shareholder at $818 million (as of Sep. 30, 2017, based on their monthly report), or $116 million above the projection at the time of the 2017 Budget
- The increase is largely due to the higher-than-projected gain on sale of OPG's head office and parking facilities during Q2.
- Over the first half of the Province's fiscal year, the total net income attributable to shareholder stands at $434 million (sum of OPG's Q2 and Q3 net income)

- Based on OPG's current fiscal year projections, an additional $384 million in net income is projected to be earned over Q4 2017 and Q1 2018.

## GENERATION DEVELOPMENT PROJECT UPDATES

| Project | Important Updates |
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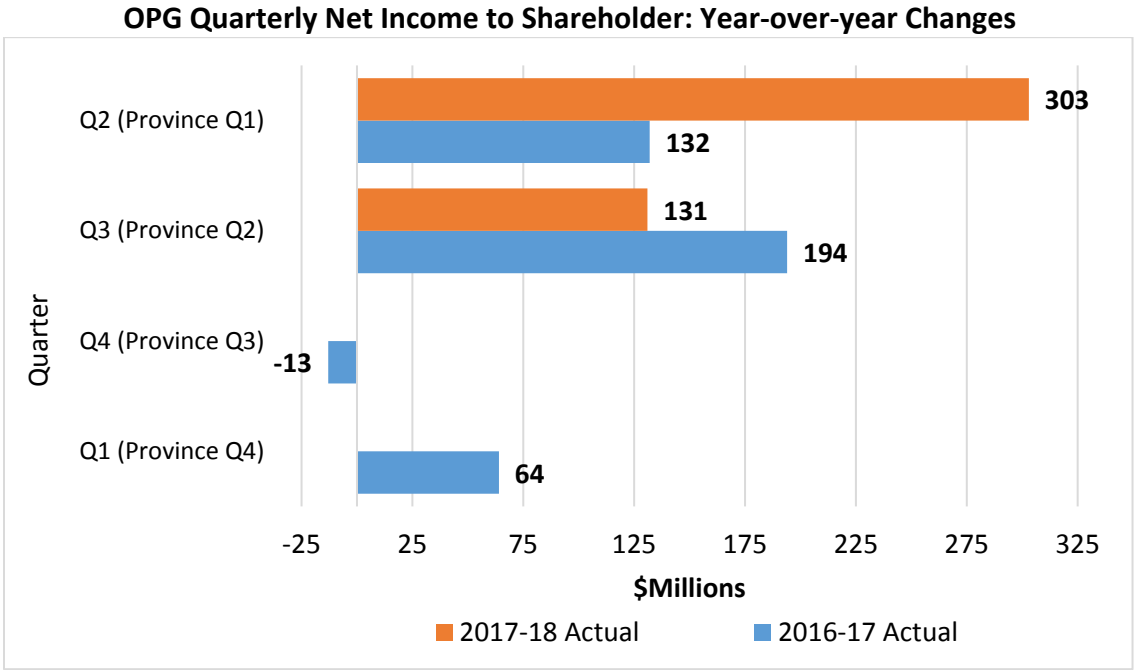
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**Electricity Finance Branch**
**Corporate Electricity Finance Division**
**November 2017**

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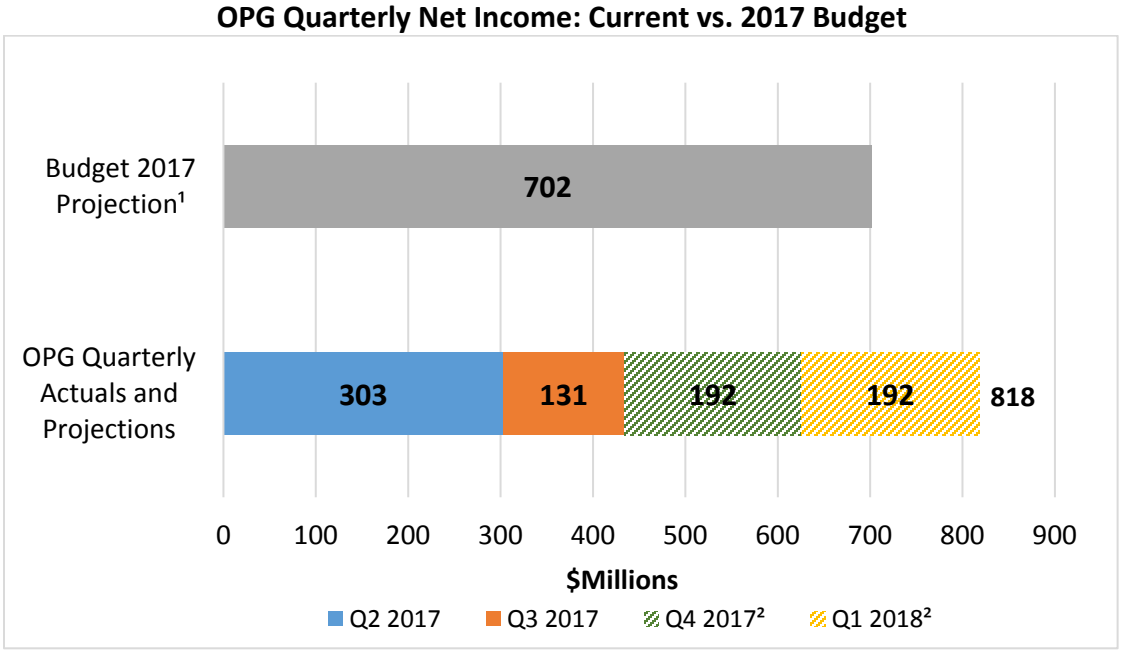
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**Electricity Finance Branch**
**Corporate Electricity Finance Division**
**November 2017**

## OPG Variance Explanation, 2016 Budget Outlook vs. Current March 2017

| | 2016-17 | 2017-18 | 2018-19 | 2019-20 |
|---|---|---|---|---|
| **Budget 2016 / Fiscal Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 471 | 586 | 673 | 705 |
| **Income Tax PILs** | 437 | 382 | 414 | 343 |
| **Earnings Before Tax** | **908** | **968** | **1087** | **1,048** |
| **OPG 2017-19 Business Plan ($M)** | | | | |
| **Net Income After Tax (Adjusted)** | 387* | 480** | 678 | 726 |
| **Income Tax PILs** | 302 | 315*** | 366 | 408 |
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| **EBT Variance to Fiscal Plan** | (219) | (173) | (43) | 86 |

NOTE: Backing out OPG head office property sale and other sums may not may not add up due to rounding.

*Includes ONFA adjustment of $8M

** After-tax gain on sale of OPG head office property of $223M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.

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Corporate and Electricity Finance Division
March 15, 2017

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Corporate and Electricity Finance Division
March 15, 2017

**Commented [GH1]:** Based on OPG's response, this impacts 2016-17 and 2017-18 fiscal

**Commented [GH2]:** I think this is the explanation between 2016-18 BP and 2017-19 BP, not for 2015-17 BP.

I don't think OPG provided much details on the changes between 2015-17 BP and 2017-19 BP, other than the rate application impact and lower nuclear production.

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| **Earnings Before Tax** | **681** | **795** | **1,044** | **1,134** |
| **EBT Variance to Fiscal Plan** | (219) | (173) | (43) | 86 |

NOTE: Backing out OPG head office property sale and other sums may not may not add up due to rounding.

*Includes ONFA adjustment of $8M

** After-tax gain on sale of OPG head office property of $223M is backed out in the net income after tax calculation in 2017-18. In 2017 Business Plan, Net Income Attributable to Shareholder in 2017-18 is $702M. The expected gain on sale is reflected as an asset optimization component captured in the Sales and Rental line under Non Tax Revenue.

*** Income Tax PILs backed out $74M income tax expense from gain on sale of OPG head office property. In 2017 Business Plan, Income Tax PILs in 2017-18 is $166M.

The changes since the 2016 Budget in the OPG outlook over the 2016-17 to 2019~~7~~-18 periods largely reflect:

- Changes in assumptions for OPG's rate application, which the 2016 Budget contemplated would be effective in 2016 but, in actuality, were filed a year later (May 2016) to be effective in the second half of 2017. This resulted in lower revenue over the 2016-17 to 2017~~8~~-18~~9~~ period. This included a higher smoothing rate of 11% in the 2017-19 OPG BP versus the 7% smoothing rate in the 2015-17 plan.
- 2016~~7~~-17~~8~~ EBT is also lower due to lower nuclear production ~~and higher OM&A expenses resulting from the deferral of the Darlington planned outage from Q1 2017 to Q2 2017~~.

Corporate and Electricity Finance Division
March 15, 2017

**Commented [GH1]:** Based on OPG's response, this impacts 2016-17 and 2017-18 fiscal

**Commented [GH2]:** I think this is the explanation between 2016-18 BP and 2017-19 BP, not for 2015-17 BP.

I don't think OPG provided much details on the changes between 2015-17 BP and 2017-19 BP, other than the rate application impact and lower nuclear production.

## OPG Net Income to Shareholder

| | | | |
|---|---|---|---|
| 2014 | Q1 | 242 | |
| | Q2 | 115 | |
| | Q3 | 361 | |
| | Q4 | 86 | |
| 2015 | Q1 | 234 | 796 |
| | Q2 | 189 | |
| | Q3 | 80 | |
| | Q4 | -101 | |
| 2016 | Q1 | 123 | 291 |
| | Q2 | 132 | |
| | Q3 | 194 | |
| | Q4 | -13 | |
| 2017 | Q1 | 64 | 377 |
| | Q2 | 303 | |
| | Q3 | 131 | |
| | Q4 | 192 | |
| 2018 | Q1 | 192 | 818 |
| | Q2 | | |
| | Q3 | | |
| | Q4 | | |
| | Q1 | | |

## Hydro One Net Income to

| | | |
|---|---|---|
| 2014 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2015 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2016 | Q1 | 208 |
| | Q2 | 152 |
| | Q3 | |
| | Q4 | |
| 2017 | Q1 | 167 |
| | Q2 | 117 |
| | Q3 | |
| | Q4 | |

33.1%

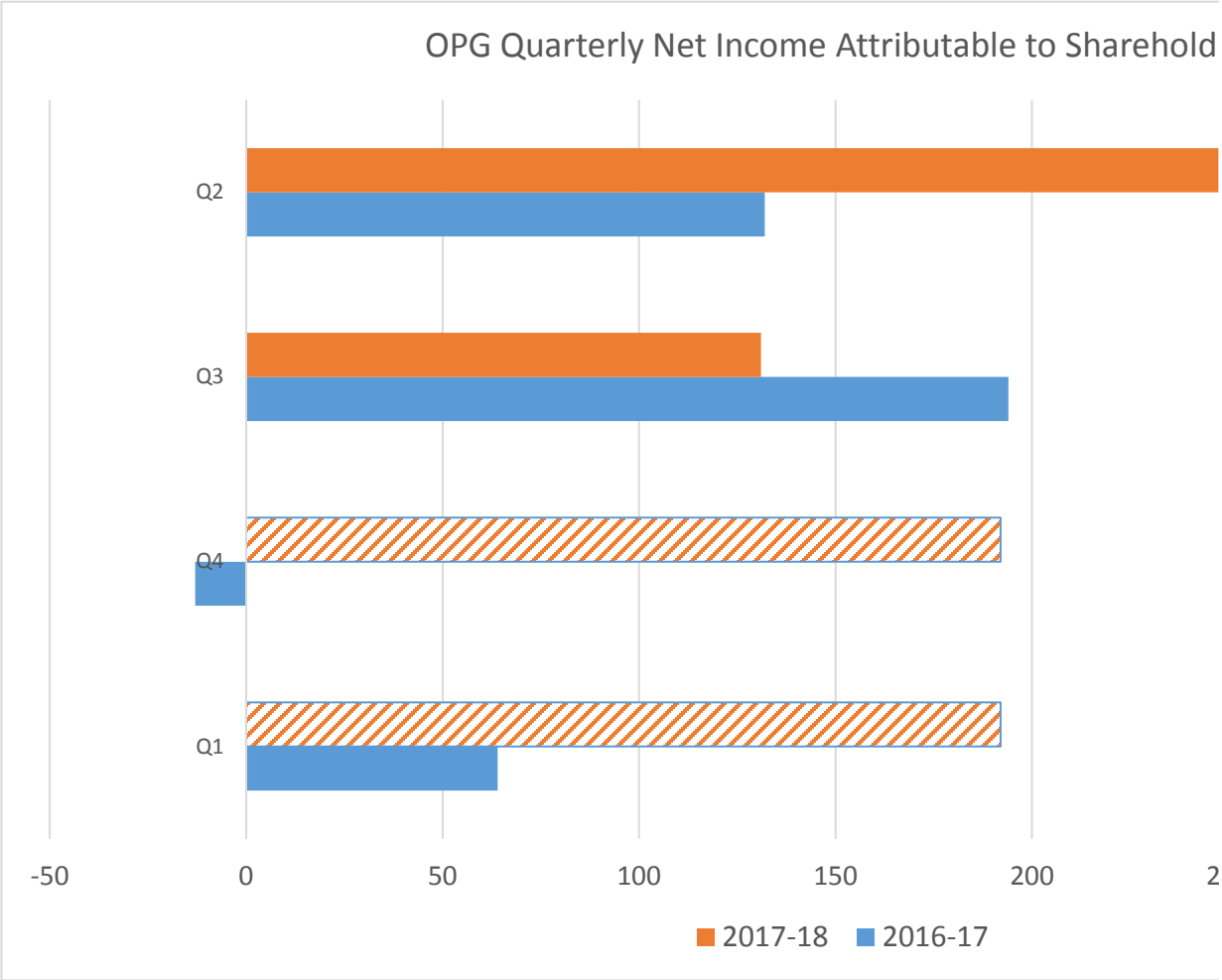
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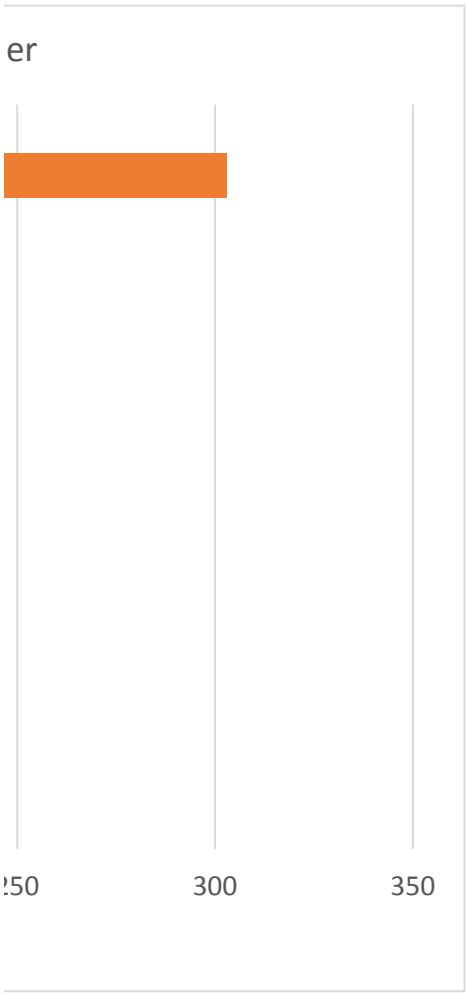
6 months

Q3 Results

| | 2016-17 | 2017-18 |
|---|---|---|
| Q1 | 64 | 192 |
| Q4 | -13 | 192 |
| Q3 | 194 | 131 |
| Q2 | 132 | 303 |

**Common Shareholders**




er
250
300
350

## OPG Net Income to Shareholder

| | | | |
|---|---|---|---|
| 2014 | Q1 | 242 | |
| | Q2 | 115 | |
| | Q3 | 361 | |
| | Q4 | 86 | |
| 2015 | Q1 | 234 | 796 |
| | Q2 | 189 | |
| | Q3 | 80 | |
| | Q4 | -101 | |
| 2016 | Q1 | 123 | 291 |
| | Q2 | 132 | |
| | Q3 | 194 | |
| | Q4 | -13 | |
| 2017 | Q1 | 64 | 377 |
| | Q2 | 303 | |
| | Q3 | 131 | |
| | Q4 | 192 | |
| 2018 | Q1 | 192 | 818 |
| | Q2 | | |
| | Q3 | | |
| | Q4 | | |
| | Q1 | | |

## Hydro One Net Income to Common

| | | |
|---|---|---|
| 2014 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2015 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2016 | Q1 | 208 |
| | Q2 | 152 |
| | Q3 | |
| | Q4 | |
| 2017 | Q1 | 167 |
| | Q2 | 117 |
| | Q3 | |
| | Q4 | |




33.1%

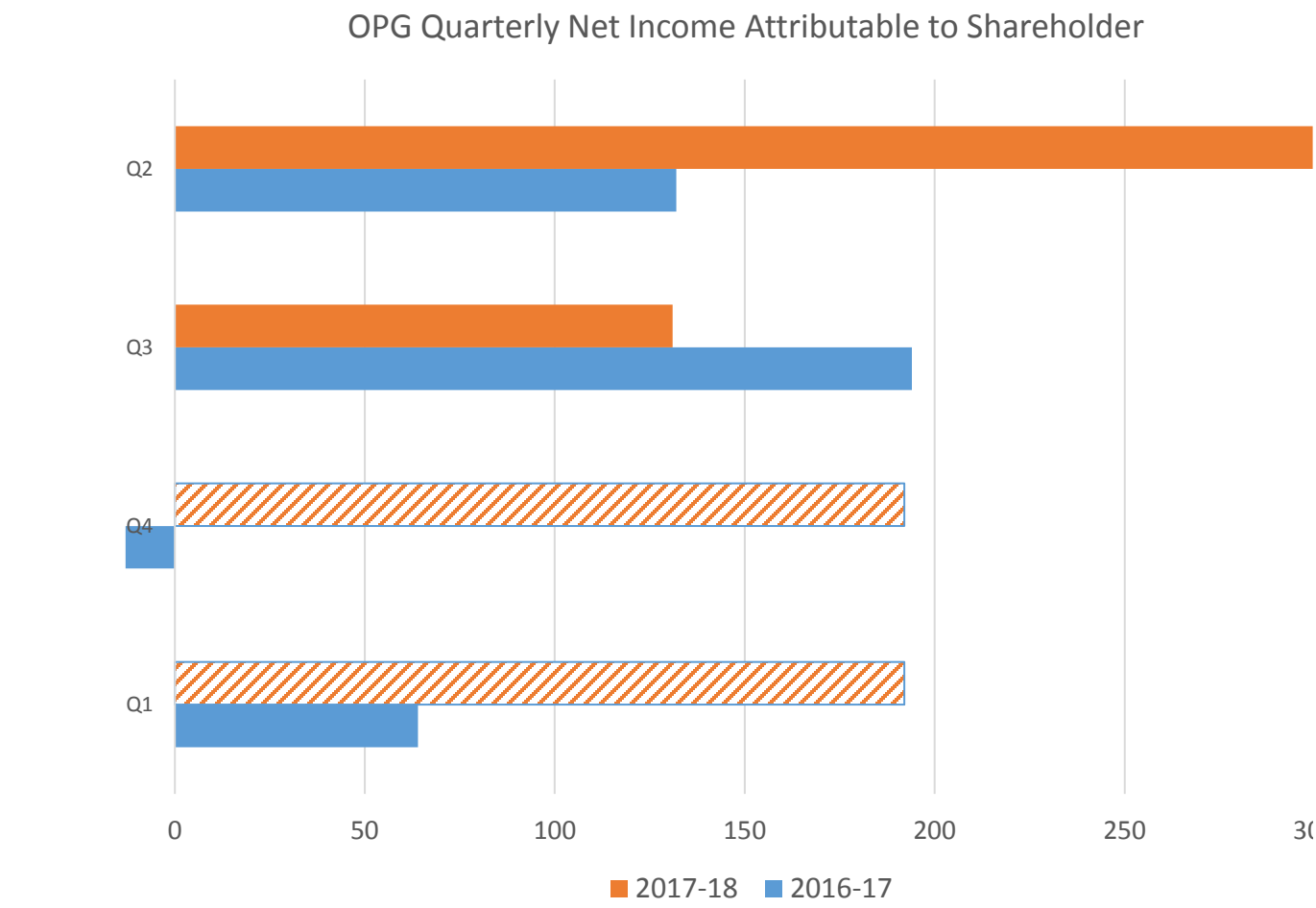
117%

6 months

Q3 Results

| | 2016-17 | 2017-18 |
|---|---|---|
| Q1 | 64 | 192 |
| Q4 | -13 | 192 |
| Q3 | 194 | 131 |
| Q2 | 132 | 303 |

**Shareholders**

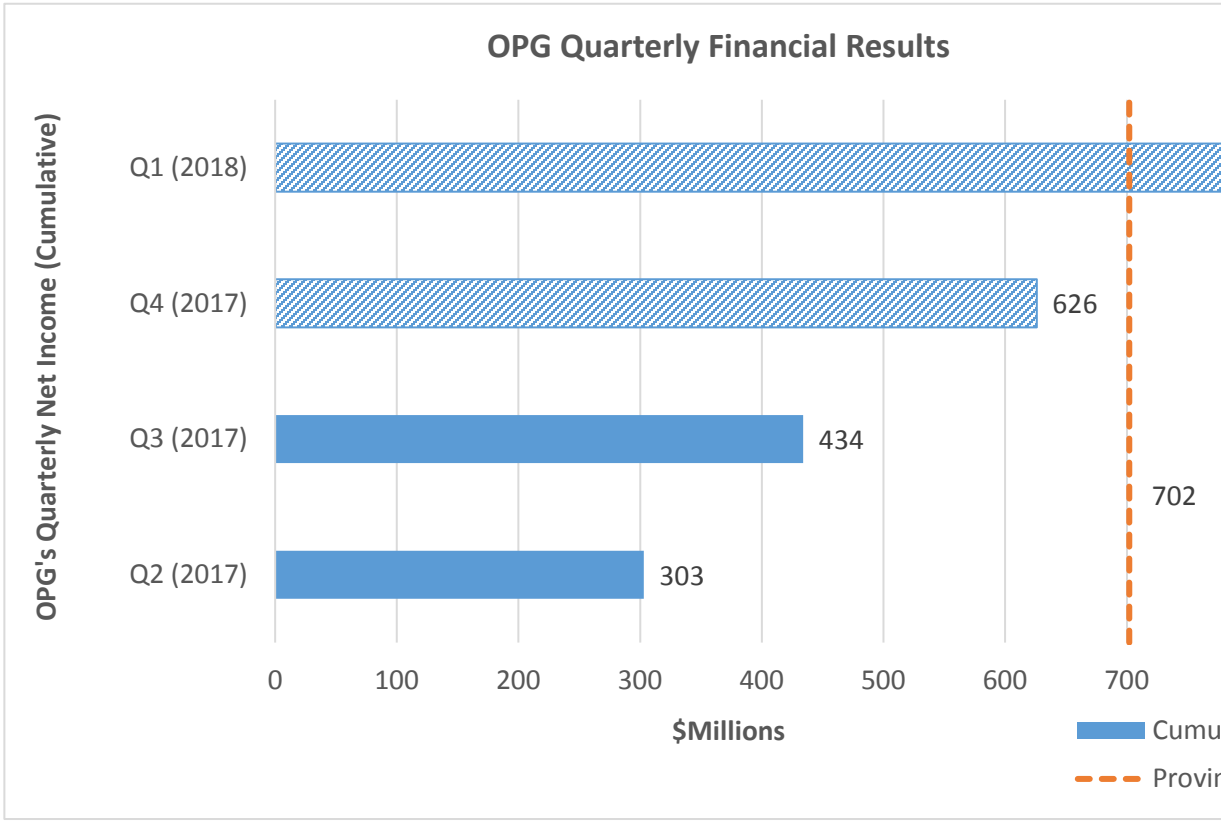



0
350

OPG Net Income Attributable to Shareholder

| Year | OPG's Quarter | Quarterly N.I. | Cumulative N.I. | |
|---|---|---|---|---|
| 2016 | Q2 (2016) | 132 | 132 | (Province's 3-months ended) |
| | Q3 (2016) | 194 | 326 | (Province's 6-months ended) |
| | Q4 (2016) | -13 | 313 | (Province's 9-months ended) |
| 2017 | Q1 (2017) | 64 | 377 | (Province's 12-months ended) |

| Year | OPG's Quarter | Quarterly N.I. | Cumulative N.I. | |
|---|---|---|---|---|
| 2017 | Q2 (2017) | 303 | 303 | (Province's 3-months ended) |
| | Q3 (2017) | 131 | 434 | (Province's 6-months ended) |
| | Q4 (2017) | 192 | 626 | (Province's 9-months ended) |
| 2018 | Q1 (2018) | 192 | 818 | (Province's 12-months ended) |



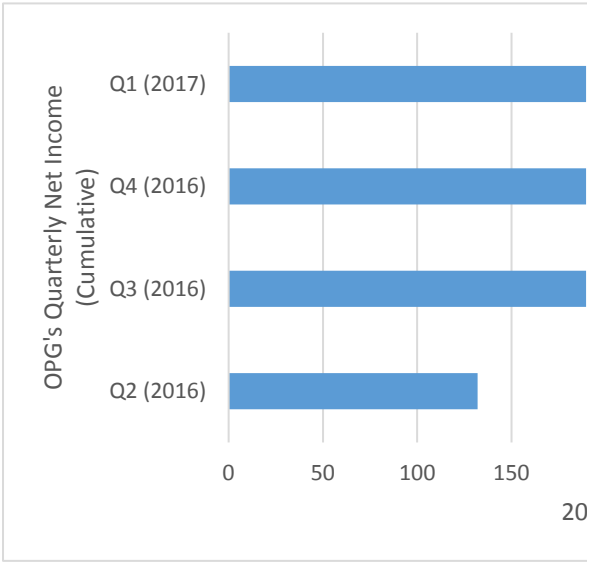
OPG's N.I. Projection for Province
(based on latest monthly report)

| | Province's N.I in Budget | Y | X |
|---|---|---|---|
| 346 | 302 | 0 | 302 |
| 349 | 302 | 1 | 302 |
| 355 | 302 | | |
| 377 | 302 | | |

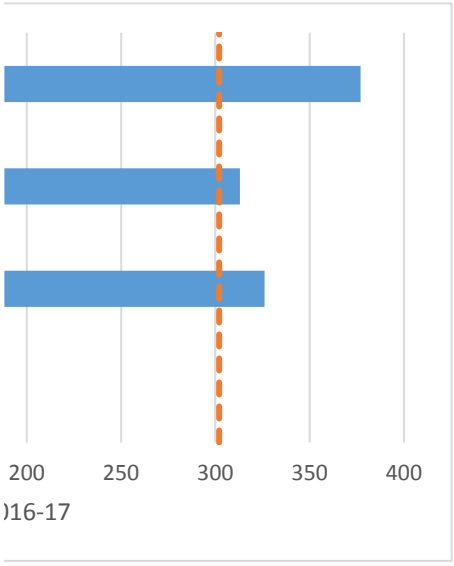
OPG's N.I. Projection for Province
(based on latest monthly report)

| | Province's N.I in Budget | Y axis | Provincial B |
|---|---|---|---|
| 787 | 702 | 0 | 702 |
| 818 | 702 | 1 | 702 |
| | 702 | | |
| | 702 | | |



Budget



## OPG Net Income to Shareholder

| | | | |
|---|---|---|---|
| 2014 | Q1 | 242 | |
| | Q2 | 115 | |
| | Q3 | 361 | |
| | Q4 | 86 | |
| 2015 | Q1 | 234 | 796 |
| | Q2 | 189 | |
| | Q3 | 80 | |
| | Q4 | -101 | |
| 2016 | Q1 | 123 | 291 |
| | Q2 | 132 | |
| | Q3 | 194 | |
| | Q4 | -13 | |
| 2017 | Q1 | 64 | 377 |
| | Q2 | 303 | |
| | Q3 | 131 | |
| | Q4 | 192 | |
| 2018 | Q1 | 192 | 818 |
| | Q2 | | |
| | Q3 | | |
| | Q4 | | |
| | Q1 | | |

## Hydro One Net Income to Common

| | | |
|---|---|---|
| 2014 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2015 | Q1 | |
| | Q2 | |
| | Q3 | |
| | Q4 | |
| 2016 | Q1 | 208 |
| | Q2 | 152 |
| | Q3 | |
| | Q4 | |
| 2017 | Q1 | 167 |
| | Q2 | 117 |
| | Q3 | |
| | Q4 | |

33.1%

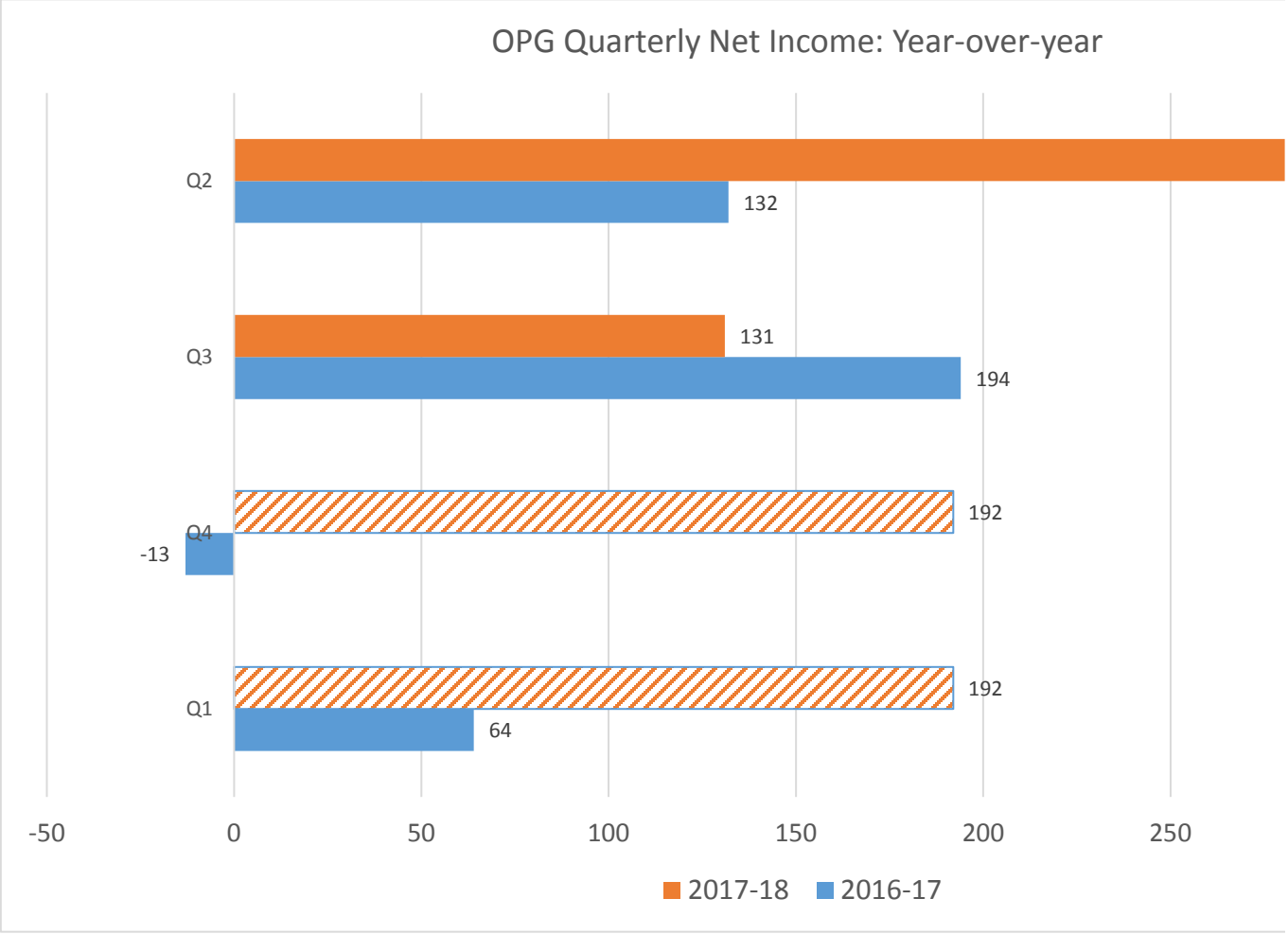
117%

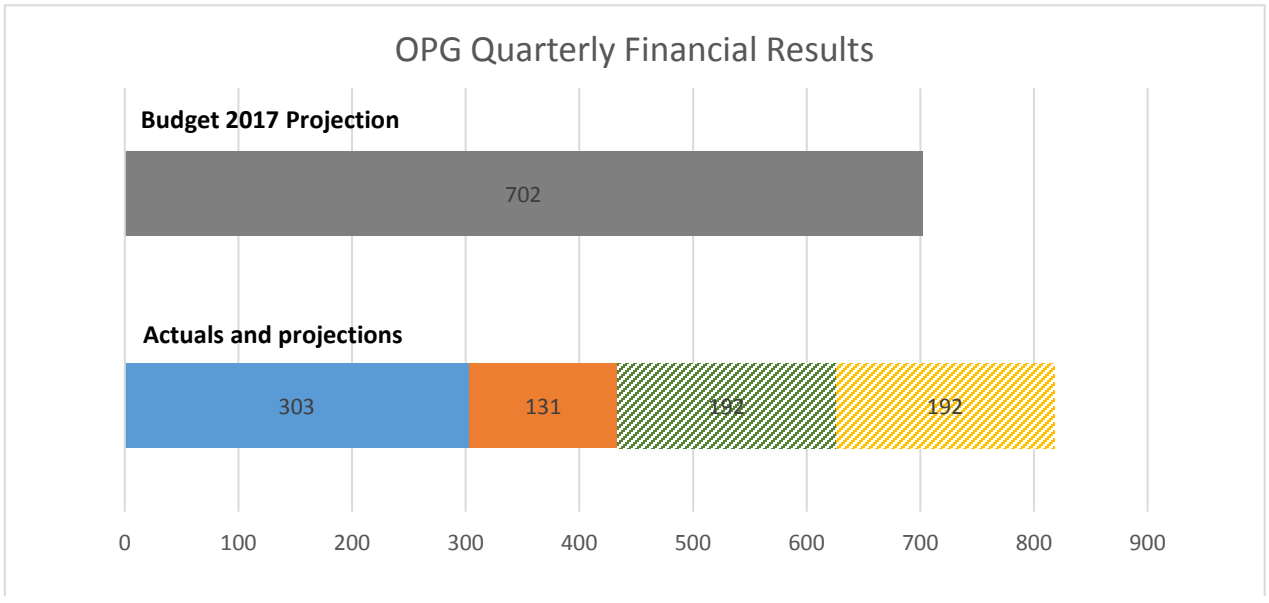
6 months

| | 2016-17 | 2017-18 | Q3 Results 2017-18 |
|---|---|---|---|
| Q1 | 64 | 192 | 818 |
| Q4 | -13 | 192 | 626 |
| Q3 | 194 | 131 | 434 |
| Q2 | 132 | 303 | 303 |

| | | |
|---|---|---|
| Q2 2017 | 303 | |
| Q3 2017 | 131 | |
| Q4 2017* | 192 | |
| Q1 2018* | 192 | 702 |

## Shareholders





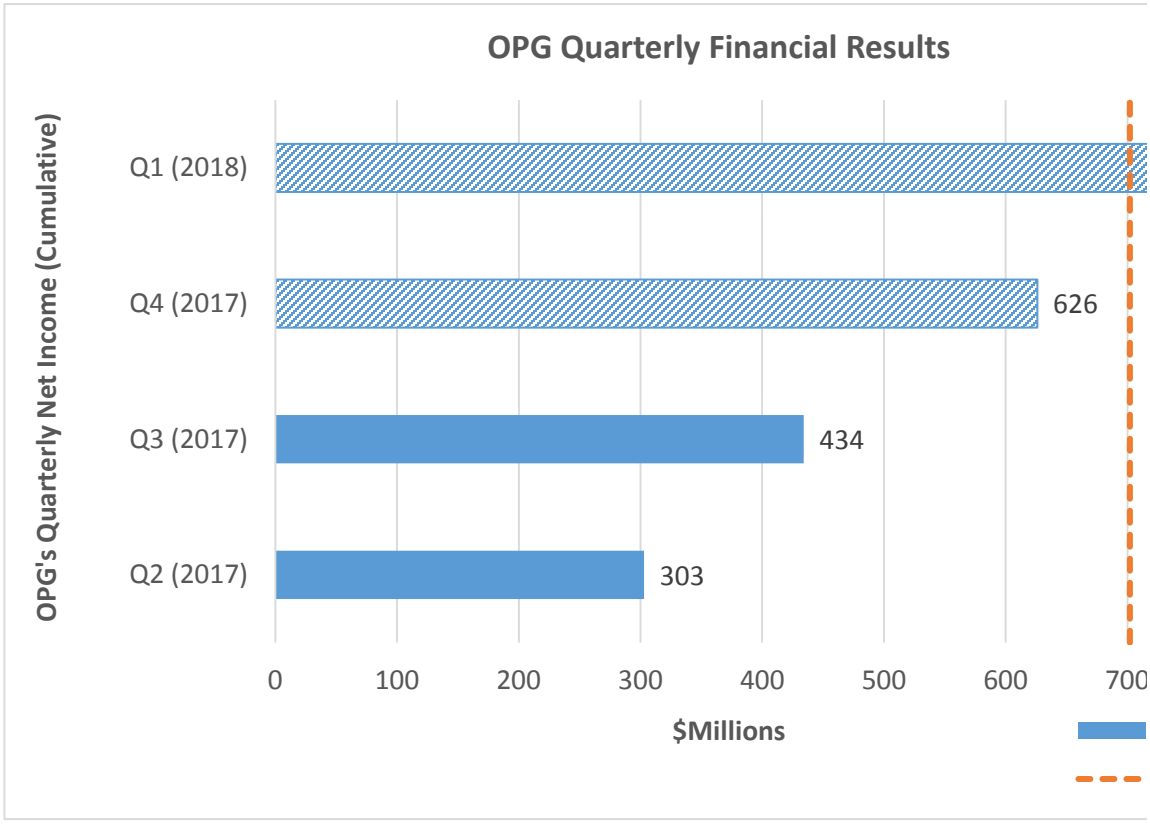

* Quarterly projections based on OPG's current year-end net income projection.


303
300
350

OPG Net Income Attributable to Shareholder

| Year | OPG's Quarter | Quarterly N.I. | Cumulative N.I. | |
|---|---|---|---|---|
| 2016 | Q2 (2016) | 132 | 132 | (Province's 3-months ended) |
| | Q3 (2016) | 194 | 326 | (Province's 6-months ended) |
| | Q4 (2016) | -13 | 313 | (Province's 9-months ended) |
| 2017 | Q1 (2017) | 64 | 377 | (Province's 12-months ended) |

| Year | OPG's Quarter | Quarterly N.I. | Cumulative N.I. | |
|---|---|---|---|---|
| 2017 | Q2 (2017) | 303 | 303 | (Province's 3-months ended) |
| | Q3 (2017) | 131 | 434 | (Province's 6-months ended) |
| | Q4 (2017) | 192 | 626 | (Province's 9-months ended) |
| 2018 | Q1 (2018) | 192 | 818 | (Province's 12-months ended) |

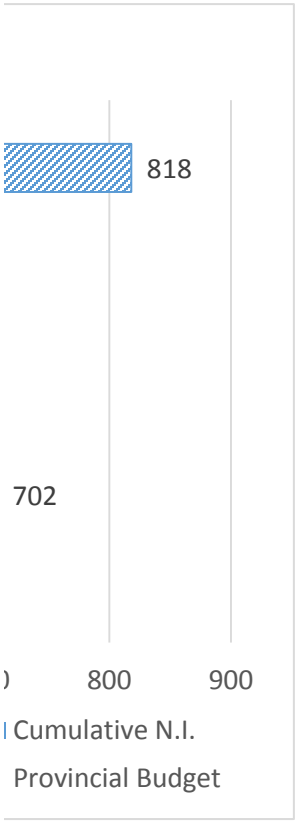


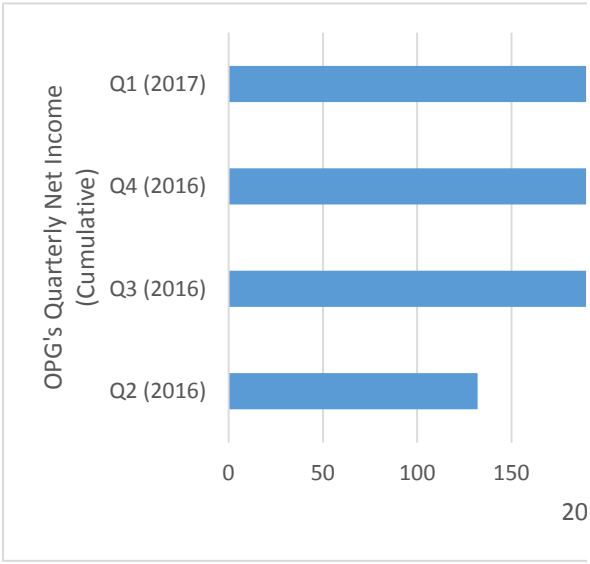
OPG's N.I. Projection for Province
(based on latest monthly report)

| | Province's N.I in Budget | Y | X |
|---|---|---|---|
| 346 | 302 | 0 | 302 |
| 349 | 302 | 1 | 302 |
| 355 | 302 | | |
| 377 | 302 | | |

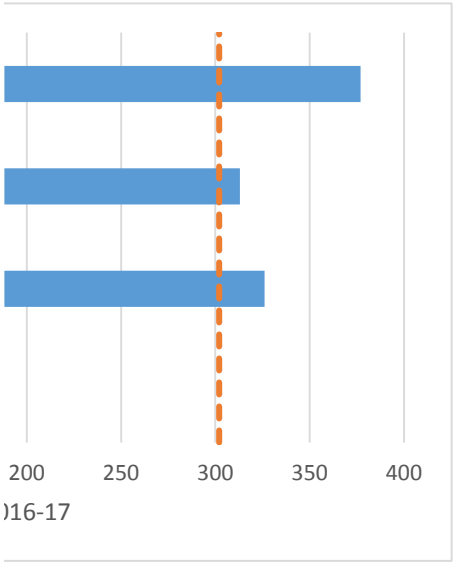
OPG's N.I. Projection for Province
(based on latest monthly report)

| | Province's N.I in Budget | Y axis | Provincial B |
|---|---|---|---|
| 787 | 702 | 0 | 702 |
| 818 | 702 | 1 | 702 |
| | 702 | | |
| | 702 | | |



Budget



## OPG Net Income Attributable to Shareholder

**Graph 1**

| Quarter | 2016-17 Actual | 2017-18 Actual |
|---|---|---|
| Q1 (Province Q4) | 64 | |
| Q4 (Province Q3) | -13 | |
| Q3 (Province Q2) | 194 | 131 |
| Q2 (Province Q1) | 132 | 303 |

**Graph 2**

| Quarter | OPG Quarterly Actuals and Projections | Budget 2017 Projection[1] |
|---|---|---|
| Q2 2017 | 303 | |
| Q3 2017 | 131 | |
| Q4 2017[2] | 0 | |
| Q1 2018[2] | 0 | 702 |

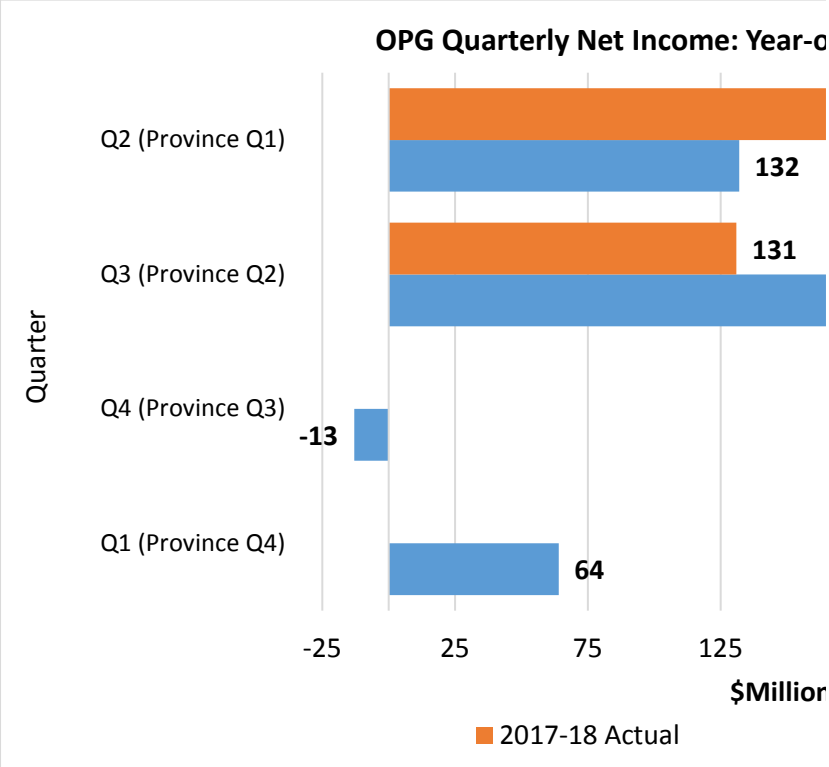
Total Net Income 2017-18

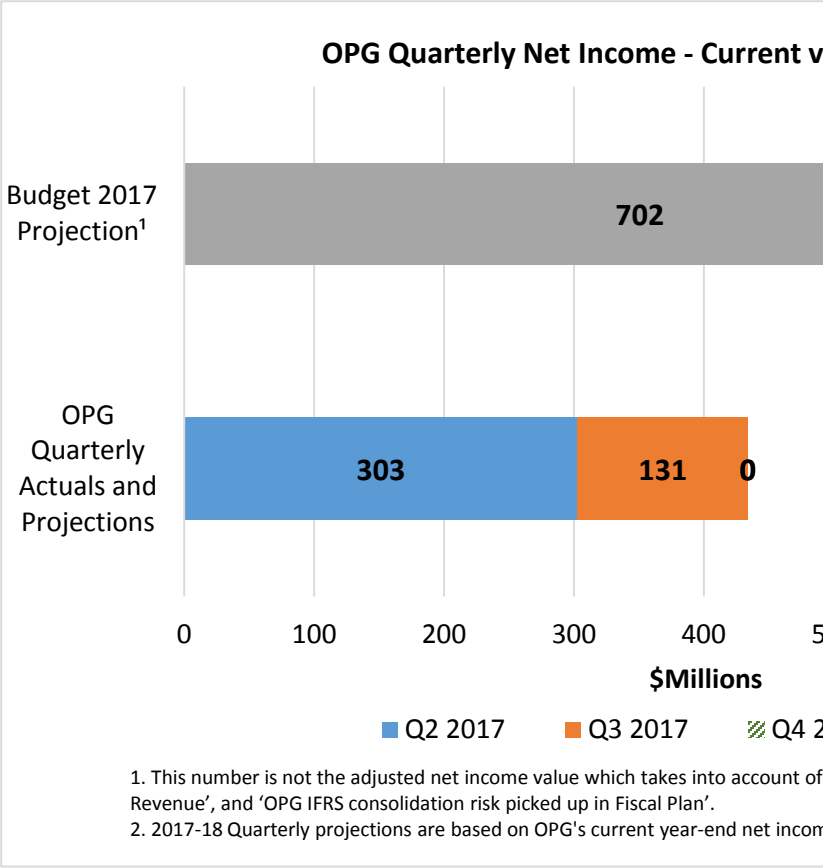
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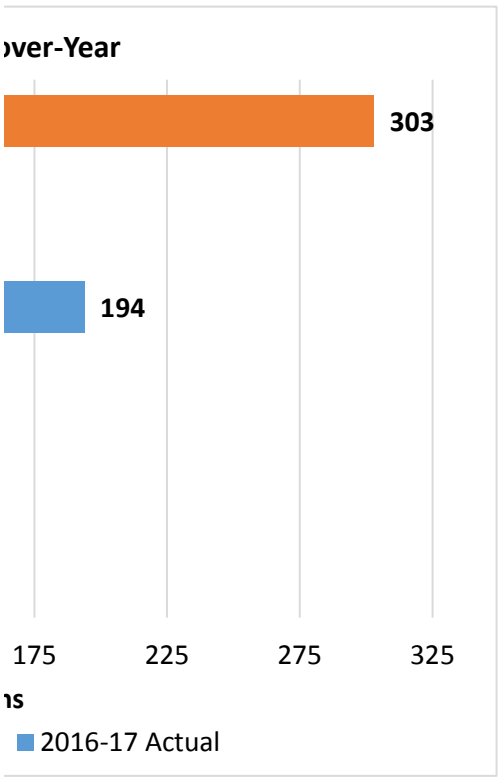
434

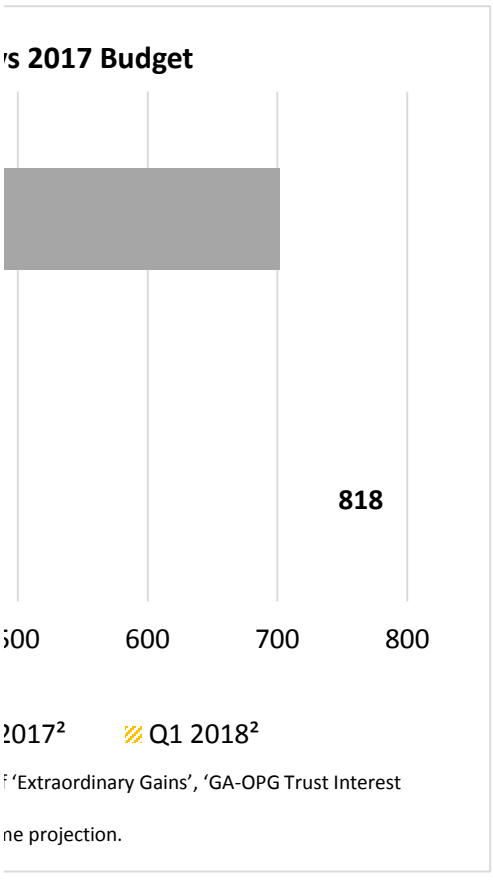
303




1. This number is not the adjusted net income value which takes into account of Revenue', and 'OPG IFRS consolidation risk picked up in Fiscal Plan'.
2. 2017-18 Quarterly projections are based on OPG's current year-end net incom




f 'Extraordinary Gains', 'GA-OPG Trust Interest

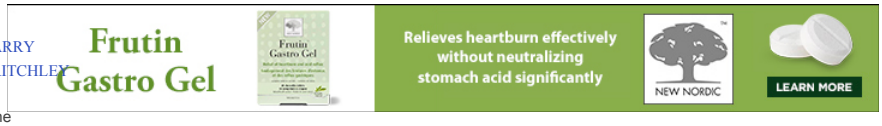
ne projection.

## OPG Net Income Attributable to Shareholder

| Year | OPG Quarter | Net Income | YoY change | OPG's Fiscal Year Net Income Projection | |
|---|---|---|---|---|---|
| 2014 | Q1 | 242 | | | |
| | Q2 | 115 | | | |
| | Q3 | 361 | | | |
| | Q4 | 86 | | | |
| 2015 | Q1 | 234 | -3.3% | 796 | |
| | Q2 | 189 | 64.3% | | |
| | Q3 | 80 | -77.8% | | |
| | Q4 | -101 | -217.4% | | |
| 2016 | Q1 | 123 | -47.4% | 291 | |
| | Q2 | 132 | -30.2% | | 108 |
| | Q3 | 194 | 142.5% | | |
| | Q4 | -13 | -87.1% | | |
| 2017 | Q1 | 64 | -48.0% | 377 | |
| | Q2 | 303 | 129.5% | | |
| | Q3 | 131 | -32.5% | | |
| | Q4 | 192 | | | |
| 2018 | Q1 | 192 | | 818 | |
| | Q2 | | | | |
| | Q3 | | | | |
| | Q4 | | | | |
| | Q1 | | | | |

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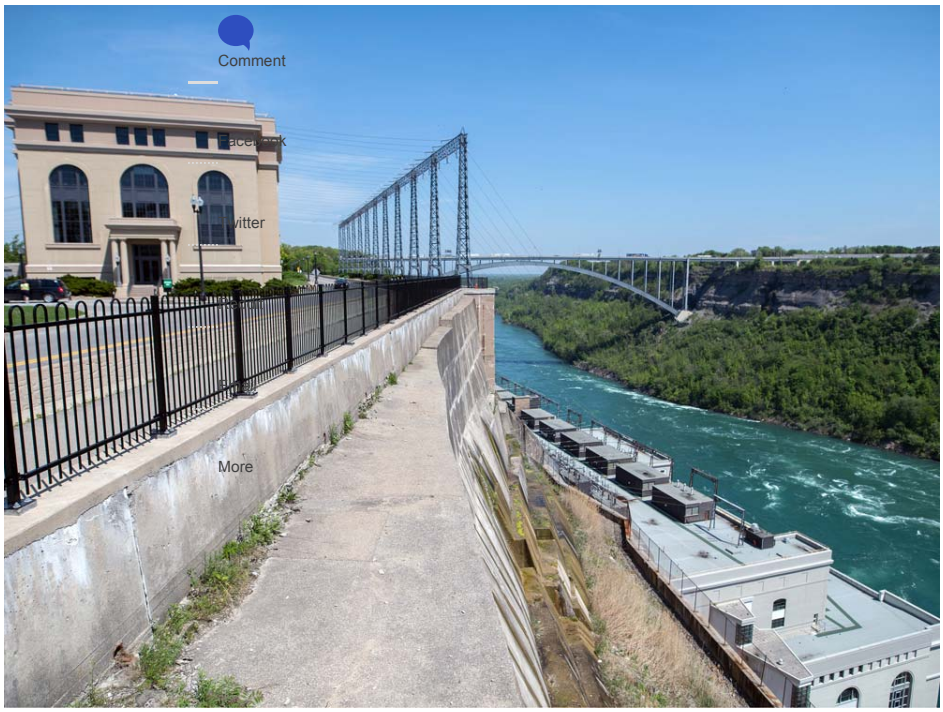
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# Ontario Power Generation set to be the next green bond issuer

On Monday, OPG posted a green bond investor presentation on SEDAR

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The Niagara River flows past the offices, control centre, and lower river level turbine and generator facility at the Ontario Power Generation Sir Adam Beck Generating Station in Niagara Falls, Ontario. *James MacDonald/Bloomberg*

The stage has been set for another issue of green bonds, the second in the past week.

This time around, Ontario Power Generation, an entity that is 100 per cent owned by the Ontario government is set to come to the market, about a week after CPPIB, the investment manager for the country's public pension plan, raised $1.5 billion in its inaugural offering. That offering is also the largest by a Canadian issuer and the first by a pension fund.

On Monday, OPG posted a green bond investor presentation on SEDAR. The amount the issuer intends to raise wasn't disclosed but the marketing materials indicated that there is $528 million of capital expenditure indicated as eligible hydro projects. Of that amount, $311 million is what has been spent



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over the past two years while the balance ($217 million) is projected for 2018. Eligible projects are defined as those that focus on renewable energy generation and which aid energy efficiency and management.

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OPG has gone the extra mile to get its upcoming green bond certified: it hired Sustainalytics for a second opinion. The research firm signed off by noting that OPG's green bond framework "is credible and impactful and aligns with the four core principles of the Green Bond Principles 2017." It based that assessment on the use of proceeds (the projects selected will have "clear positive environmental impacts,"); on project evaluation and selection; on management of the proceeds; and on reporting (OPG will report annually on how the proceeds are allocated).

OPG, which is Ontario's largest clean energy generator, owns 72-generation facilities, of which 66 are hydro and two are nuclear. In those marketing materials, it said that following the closing of its coal-fired generation plants, 99 per cent of the power it produces is "free of smog and greenhouse gas emissions."

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If and when it issues green bonds, it will mark its second domestic bond offering: last October it raised $500 million of 10-year money at a coupon of 3.315 per cent. In September 2017, it established a $2 billion medium term note program.

BMO Capital Markets and TD Securities have been chosen as the lead bookrunners. OPG has a split rating: DBRS has assigned an A (low) rating while S&P has assigned a BBB+ rating.

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www.opg.com

Mar. 8, 2018

# OPG REPORTS 2017 FINANCIAL RESULTS

## *OPG records increase in net income for third consecutive year*

**[Toronto]:** – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder of $860 million for 2017, compared to $436 million in 2016.

"As stewards of Ontario's publicly-owned generating assets, I am pleased with our strong 2017 financial results, which marks the third year-over-year increase in net income. OPG's major focus remains on the largest clean energy project in Canada, the refurbishment of the Darlington Nuclear Generating Station. This ten-year project will extend the life of this asset and ensure a safe, reliable, and clean source of electricity for another 30 years," said Jeff Lyash, OPG President and CEO. "The refurbishment of Darlington's Unit 2 recently passed the halfway point based on work performed, and remains on time and on budget due to the hard work and dedication of our employees and partners. This success was recognized by our shareholder, the Province of Ontario, who has confirmed its commitment to proceed with Darlington's Unit 3 refurbishment."

Lyash continued, "The Pickering Nuclear Generating Station has significantly improved its operating performance over last year, by increasing its capability factor to 80 per cent in 2017. By continuing to operate this important asset to 2024, we will ensure a safe and clean source of reliable power during the refurbishment of Darlington. OPG has applied to its regulator, the Canadian Nuclear Safety Commission, for a licence to keep Pickering online until 2024, and we expect a decision on this application in 2018."

"We are also continuing to invest in our hydroelectric generating fleet. The Peter Sutherland Sr. Hydroelectric Generating Station was completed in 2017, on budget and ahead of schedule, and is the latest example of OPG's commitment to working closely in partnership with Indigenous communities," added Lyash.

The Ontario Energy Board's (OEB) decision on OPG's application for new regulated prices for the 2017-2021 period was issued in December 2017. The regulated prices apply to all of OPG's nuclear and most of its hydroelectric generation. The decision determined that new prices would be applied with an effective date of June 1, 2017. In January 2018, OPG submitted a draft payment amounts order to the OEB that implemented the decision's findings into the final proposed regulated prices. OPG recognized the impact of the OEB's decision in the fourth quarter of 2017, which resulted in net revenue of approximately $480 million related to the June 1, 2017 to December 31, 2017 period. This increase in revenue was partially offset by the year-

over-year reduction in nuclear electricity generation, primarily due to the Darlington Refurbishment, the impact of which was not reflected in the regulated prices that continued to be in effect prior to the June 1, 2017 effective date of the new prices.

The OEB is expected to issue the final payment amounts order in the first half of 2018, at which time OPG will begin to collect revenues based on new regulated prices. The OEB's approval of the final payment amounts order is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017 to reflect the impact of the OEB's decision. Taking into account the impact of the OEB's decision, OPG continues to provide electricity at a price that is 40 per cent less than the average of other generators. OPG is the only electricity generator in Ontario that has its prices set through a public hearing process by the OEB.

The after-tax gain of $283 million on the sale of OPG's head office building and parking facility recorded in the second quarter of 2017 contributed to the year-over-year increase in net income. Higher earnings from the Regulated – Nuclear Waste Management segment were also recognized in 2017, primarily due to higher earnings on the nuclear fixed asset removal and nuclear waste management segregated funds.

OPG has been appointed the Financial Services Manager under the *Ontario Fair Hydro Plan Act*, *2017* (the Act) and, in December 2017, established the Fair Hydro Trust (the Trust) as the financing entity contemplated by the Act. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. In December 2017, the Trust purchased its first tranche of financing receivable assets from the Independent Electricity System Operator in the amount of approximately $1.2 billion. In February 2018, the Trust issued $500 million of senior notes payable maturing in 2033.

**Generating and Operating Performance**

Electricity generated in 2017 decreased to 74.1 terawatt hours (TWh) from 78.2 TWh in 2016. The decrease in electricity generation reflected the expected lower generation from the Darlington GS and lower generation from the contracted plants. The decrease was partially offset by higher generation from the Pickering GS, primarily due to fewer outage days, and higher generation from the regulated hydroelectric stations.

*Regulated – Nuclear Generation Segment*

Lower nuclear generation of 4.9 TWh during 2017 was primarily due to the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment that began in October 2016 and is expected to continue until early 2020. Partly offsetting the reduction in generation from the Darlington GS was an increase in generation of 1.5 TWh from the strong performance of the Pickering GS during 2017.

For 2017, the unit capability factor for the operating units at the Darlington GS was 85.2 per cent, compared to 89.5 per cent for 2016. The decrease was primarily a result of a higher number of planned outage days at the station in 2017, largely driven by the planned transition of the station towards refurbishment.

At the Pickering GS, the unit capability factor increased to 80.0 per cent for 2017, compared to 75.2 per cent for 2016, primarily due to outage cycle optimization and

execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station in 2017.

*Regulated – Hydroelectric Segment*

Higher generation from the regulated hydroelectric stations of 1.2 TWh during 2017 compared to 2016 was due to higher water flows, primarily on the eastern Ontario river systems.

The availability of 88.0 per cent at these stations in 2017 was slightly lower than 89.0 per cent for 2016. The decrease in the availability was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara regions' hydroelectric stations, partially offset by a higher number of planned outage days in 2016 as a result of refurbishing the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017.

*Contracted Generation Portfolio Segment*

Lower generation from the Contracted Generation Portfolio of 0.4 TWh during 2017, compared to 2016, was mainly due to higher surplus baseload generation conditions.

The availability of these hydroelectric stations for 2017 was 74.6 per cent, compared to 77.3 per cent for 2016. The decrease in the availability was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

*Total Generating Cost*

The Enterprise Total Generating Cost per megawatt hour (MWh) for 2017 was $50.66, compared to $48.45 for 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, which were partially offset by higher hydroelectric electricity generation adjusted for surplus baseload generation.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusted for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise Total Generating Cost would have been approximately $4 to $5 per MWh lower for 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

**Generation Development**

OPG is undertaking a number of generation development and life extension projects in support of Ontario's electricity planning initiatives. Significant developments during 2017 were as follows:

*Darlington Refurbishment*

The Darlington Refurbishment project is expected to extend the operating life of the four-unit Darlington GS by approximately 30 years. The approved budget for the four-

unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. In October 2016, OPG commenced the refurbishment of the first unit, Unit 2. The de-fuelling of the reactor and islanding of Unit 2 were completed in the first half of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components began in August 2017, with the removal of all 960 feeder tubes completed in September 2017. The removal of fuel channel assemblies is in progress. The removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The Re-tube Waste Processing Building was completed in November 2017. Construction to complete the Heavy Water Storage and Drum Handling Facility (HWSF) recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. Taking into account the execution performance of the Unit 2 refurbishment and the cost to complete the HWSF, the overall Darlington Refurbishment project continues to track to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the refurbishment of the second unit. In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of Unit 3.

Total life-to-date capital expenditures on the project were approximately $4.4 billion as at December 31, 2017.

*Ranney Falls Hydroelectric GS*

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

*Nanticoke Solar Facility*

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, will commence with site preparation work in March 2018. During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction.

Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility will operate under a contract with the IESO and is expected to be completed in the first quarter of 2019, with a budget of $107 million.

## FINANCIAL AND OPERATIONAL HIGHLIGHTS

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| Revenue | **5,158** | 5,653 |
| Fuel expense | **689** | 727 |
| Gross margin | **4,469** | 4,926 |
| Operations, maintenance and administration | **2,824** | 2,747 |
| Depreciation and amortization | **679** | 1,257 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **960** | 929 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(801)** | (746) |
| Earnings from Fair Hydro Trust | **(1)** | - |
| Income from investments subject to significant influence | **(38)** | (37) |
| Other net (gains) expenses | **(339)** | 35 |
| Income before interest and income taxes | **1,185** | 741 |
| Net interest expense | **95** | 120 |
| Income tax expense | **209** | 168 |
| Net income | **881** | 453 |
| **Net income attributable to the Shareholder** | **860** | 436 |
| **Net income attributable to non-controlling interest** [1] | **21** | 17 |
| ***Income before interest and income taxes*** | | |
| Electricity generation business segments | **971** | 928 |
| Regulated – Nuclear Waste Management | **(150)** | (174) |
| Services, Trading, and Other Non-Generation | **364** | (13) |
| Fair Hydro Trust | **-** | - |
| Total income before interest and income taxes | **1,185** | 741 |
| ***Cash flow*** | | |
| Cash flow provided by operating activities | **944** | 1,817 |
| ***Electricity generation (TWh)*** | | |
| Regulated – Nuclear Generation | **40.7** | 45.6 |
| Regulated – Hydroelectric | **30.7** | 29.5 |
| Contracted Generation Portfolio [2] | **2.7** | 3.1 |
| Total electricity generation | **74.1** | 78.2 |
| ***Nuclear unit capability factor (per cent)*** [3] | | |
| Darlington Nuclear GS | **85.2** | 89.5 |
| Pickering Nuclear GS | **80.0** | 75.2 |
| ***Availability (per cent)*** | | |
| Regulated – Hydroelectric | **88.0** | 89.0 |
| Contracted Generation Portfolio – hydroelectric stations | **74.6** | 77.3 |
| ***Equivalent forced outage rate*** | | |
| Contracted Generation Portfolio – thermal stations | **2.4** | 1.6 |
| *Enterprise Total Generating Cost (TGC) per MWh for the twelve months ended December 31, 2017 and 2016 ($/MWh)* [4] | **50.66** | 48.45 |
| *Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI) for the twelve months ended December 31, 2017 and 2016 (%)* [4] | **7.6** | 4.2 |
| *Funds from Operations (FFO) Adjusted Interest Coverage for the twelve months ended December 31, 2017 and 2016 (times)* [4] | **3.3** | 5.1 |

[1] Relates to the 25 per cent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation in the Lower Mattagami Limited Partnership, the 33 per cent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 per cent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 per cent in April 2017.

[2] Includes OPG's share of generation volume from its 50 per cent ownership interests in the Portlands Energy Centre and Brighton Beach GS.

[3] Nuclear unit capability factor excludes unit(s) during the period in which they are undergoing refurbishment. Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

[4] Enterprise TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about the non-GAAP measures is provided in OPG's Management's Discussion and Analysis for the year ended December 31, 2017, in the sections *Highlights – FFO Adjusted Interest Coverage*, *Highlights – Return on Equity Excluding Accumulated Other Comprehensive Income*, and *Highlights – Enterprise Total Generating Cost per MWh*, as well as *Supplementary Non-GAAP Financial Measures.*

Ontario Power Generation Inc. is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. Our mission is providing low cost power in a safe, clean, reliable and sustainable manner for the benefit of our customers and shareholder.

Ontario Power Generation Inc.'s audited consolidated financial statements and Management's Discussion and Analysis as at and for the year ended December 31, 2017 can be accessed on OPG's web site (www.opg.com), the Canadian Securities Administrators' web site (www.sedar.com), or can be requested from the Company.

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# ONTARIO POWER GENERATION INC.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

**DECEMBER 31, 2017**

ONTARIO POWER GENERATION

**2017 YEAR-END REPORT**

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# ONTARIO POWER GENERATION INC.
## MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2017. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) that allows OPG to apply US GAAP. The current OSC exemption was issued in 2014 and is in effect up to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP*. This MD&A is dated March 8, 2018.

### FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, operating licence applications to the Canadian Nuclear Safety Commission (CNSC), health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, Ontario's Fair Hydro Plan (Fair Hydro Plan) and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC), Operations, Maintenance and Administration (OM&A) expenditures, retention of critical talent, supplier and third party performance, and project expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

## THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) (OBCA) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at December 31, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

### OPG's Reporting Structure

The composition of OPG's reportable business segments effective in the fourth quarter of 2017 is as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

In the fourth quarter of 2017, OPG modified its reportable business segments to include the Fair Hydro Trust segment, following the establishment of the Fair Hydro Trust (the Trust) in December 2017 as the financing entity to implement the Fair Hydro Plan under the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act). Through its control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP. The Fair Hydro Trust segment reports the income related to OPG's role as the Financial Services Manager under the Act and holder of the Trust's subordinated debt, and includes the financial results of the Trust. The Fair Hydro Plan and the Fair Hydro Trust are discussed in the sections, *Recent Developments* and *Business Segments*.

OPG receives regulated prices for electricity generated from most of its hydroelectric facilities and all of the nuclear facilities that it operates (collectively, prescribed facilities or regulated facilities). The regulated facilities comprise 54 hydroelectric generating stations across a number of major river systems in the province, the Pickering Nuclear GS (Pickering GS) and the Darlington Nuclear GS (Darlington GS).

The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's operating generating facilities, the operating results are described under the Contracted Generation Portfolio segment. A description of all of OPG's segments is provided in the section, *Business Segments*.

## In-Service Generating Capacity

OPG's in-service generating capacity by business segment as of December 31 was as follows:

| *(MW)* | **2017** | **2016** |
|---|---|---|
| Regulated – Nuclear Generation [1] | **5,728** | 5,728 |
| Regulated – Hydroelectric | **6,426** | 6,421 |
| Contracted Generation Portfolio [2] | **4,056** | 4,028 |
| Total | **16,210** | 16,177 |

[1] The in-service generating capacity as of December 31, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

The total in-service capacity as at December 31, 2017 increased by 33 MW compared to 2016. The increase was primarily due to the completion of the 28 MW Peter Sutherland Sr. hydroelectric GS, which was placed in-service in the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017. Further details on the Peter Sutherland Sr. GS project are found in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

## REVENUE MECHANISMS FOR REGULATED AND NON-REGULATED GENERATION

### Regulated Generation

The OEB sets the prices for electricity generated from OPG's nuclear and regulated hydroelectric facilities. The following table presents the OEB-authorized regulated prices for electricity generated from these facilities during the periods from January 1, 2016 to May 31, 2017, as well as new regulated prices retrospectively effective June 1, 2017 that OPG has calculated and submitted to the OEB, based on the OEB's decision on OPG's 2017-2021 application for new regulated prices issued on December 28, 2017:

| *($/MWh)* | 2017 | | 2016 |
|---|---|---|---|
| | **January 1 to May 31** | **June 1 to December 31** [1] | |
| **Regulated – Nuclear Generation** | | | |
| Base regulated price | **59.29** | **80.65** | 59.29 |
| Variance and deferral account rate rider | **-** | **-** | 10.84 [3] |
| | **59.29** | **80.65** | 70.13 |
| **Regulated – Hydroelectric** | | | |
| Base regulated price | **40.72** [2] | **41.67** | 40.72 [2] |
| Variance and deferral account rate rider | **-** | **-** | 3.19 [3] |
| | **40.72** | **41.67** | 43.91 |

[1] Regulated prices for the June 1, 2017 to December 31, 2017 period were calculated and submitted to the OEB by OPG in January 2018 based on the OEB's December 28, 2017 decision on OPG's 2017-2021 application for new regulated prices. The final regulated prices will be determined by the OEB as part of the payment amounts order process, which is expected to be completed in the first half of 2018. As part of the process, the OEB is expected to authorize separate rate riders to allow for the recovery of the shortfall between the new regulated prices and the previously approved regulated prices that OPG continues to receive during the interim period between June 1, 2017 and the implementation date of the new regulated prices. The revenue for the period between June 1, 2017 and December 31, 2017 arising from this retrospective application of the new regulated prices submitted by OPG in January 2018 was accrued in 2017.

[2] Separate base regulated prices were in effect for hydroelectric facilities prescribed for OEB rate regulation effective prior to 2014 and those prescribed for OEB rate regulation effective in 2014. The table displays a production-weighted average base regulated price for all of these facilities based on OEB-approved forecast production. A single base regulated price will apply to all prescribed hydroelectric facilities effective June 1, 2017.

[3] The OEB authorized interim period rate riders for the period from October 1, 2015 to December 31, 2016 to allow for the recovery of the variance and deferral account riders effective July 1, 2015 for the period from July 1, 2015 to September 30, 2015. The nuclear interim period rate rider was $2.17 per megawatt hour (MWh) and the regulated hydroelectric interim period rate rider was $0.64/MWh. These interim period rate riders have not been included in the above table. All rate riders in effect during 2016 expired on December 31, 2016.

Based on the OEB's December 2017 decision, the new base regulated prices will be determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices for each of the years 2017 to 2021 will be determined using a formula that annually escalates the previously approved regulated prices, subject to some adjustments, based on an industry-specific weighted inflation factor less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices will be determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years 2017 to 2021 is based on the OEB-approved forecasts of operating costs as reduced by a stretch factor amount and a return on rate base. Rate base for OPG represents the average net level of investment in regulated fixed and intangible assets in service and an allowance for working capital. The OEB's December 2017 decision and resulting new regulated prices calculated by OPG are discussed further in the section, *Recent Developments*.

The base regulated prices in effect during 2016 were established by the OEB's November 2014 decision and December 2014 order, effective November 1, 2014, using a forecast cost-of-service methodology based on the OEB-approved revenue requirements for the 2014 to 2015 period, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities and a return on rate base.

The increase in base regulated prices for the Regulated – Nuclear Generation segment from those last approved in 2014 is driven primarily by lower production from the Darlington GS for the duration of the station's refurbishment and the increase in rate base and depreciation expense related to the refurbishment project expenditures. The increase in base regulated prices also reflects recovery of costs to enable the operation of the Pickering GS beyond 2020 in line with Ontario's Long-Term Energy Plan (LTEP).

Variance and deferral account rate riders for OPG are established to recover or repay approved balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts). Variance and deferral accounts typically capture, for subsequent review and approval, differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The rate riders in effect to the end of 2016 were established by the OEB's October 2015 order on OPG's 2014 application to recover the December 31, 2014 regulatory account balances. Revenue received from the recovery of regulatory account balances is largely offset by amortization expense related to these balances.

### Non-Regulated Generation

Electricity generated from most of OPG's non-regulated assets is subject to Energy Supply Agreements (ESAs) with the Independent Electricity System Operator (IESO).

During 2017, ESAs were in effect for the following thermal generating facilities:

- Lennox GS: Capacity and production provided by the station are subject to an ESA for the period from January 1, 2013 to September 30, 2022
- Atikokan GS: Capacity and production provided by the station are subject to a ten-year ESA expiring in July 2024
- Thunder Bay GS: Capacity and production provided by the station are subject to a five-year ESA expiring in January 2020.

In addition, long-term hydroelectric ESAs are in place for the following facilities, with expiry dates ranging from 2059 to 2067:

- Lac Seul and Ear Falls generating stations
- Healey Falls GS
- Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations
- Little Long, Harmon, Smoky Falls, and Kipling generating stations (collectively, the Lower Mattagami River hydroelectric generating stations)
- Peter Sutherland Sr. GS.

## HIGHLIGHTS

### Overview of Results

This section provides an overview of OPG's operating results for the years ended December 31, 2017 and December 31, 2016.

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| Revenue | **5,158** | 5,653 |
| Fuel expense | **689** | 727 |
| Gross margin | **4,469** | 4,926 |
| Operations, maintenance and administration | **2,824** | 2,747 |
| Depreciation and amortization | **679** | 1,257 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **960** | 929 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(801)** | (746) |
| Earnings from Fair Hydro Trust | **(1)** | - |
| Income from investments subject to significant influence | **(38)** | (37) |
| Property taxes | **40** | 46 |
| Restructuring | **-** | 6 |
| | **3,663** | 4,202 |
| Income before other gains, interest, and income taxes | **806** | 724 |
| Other gains | **379** | 17 |
| Income before interest and income taxes | **1,185** | 741 |
| Net interest expense | **95** | 120 |
| Income before income taxes | **1,090** | 621 |
| Income tax expense | **209** | 168 |
| Net income | **881** | 453 |
| Net income attributable to the Shareholder | **860** | 436 |
| Net income attributable to non-controlling interest [1] | **21** | 17 |
| *Electricity production (TWh)* [2] | **74.1** | 78.2 |
| *Cash flow* | | |
| Cash flow provided by operating activities | **944** | 1,817 |

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation (CRP), a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership (PSS), and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP. CRP increased its partnership interest in PSS to 33 percent in April 2017.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Net income attributable to the Shareholder was $860 million for 2017, representing an increase of $424 million compared to 2016. Income before interest and income taxes was $1,185 million for 2017, representing an increase of $444 million compared to 2016. The following summarizes the significant factors which contributed to the variance:

*Significant factors that increased income before interest and income taxes:*

- Net revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the impact of OEB's decision on OPG's application for new regulated rates issued in December 2017 with a retrospective effective date of June 1, 2017. This revenue increase related to the June 1, 2017 to December 31, 2017 period was

recorded as an increase in regulatory assets, based on new regulated prices for that period proposed in OPG's January 2018 draft payment amounts order submission to the OEB based on the findings in the OEB's decision, net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal included in that submission. A payment amounts order process typically follows the issuance of an OEB decision on a major rates application. The OEB's approval of the final payment amounts order, including determinations on the new regulated prices and rate smoothing, are not expected to have a material impact on the total net revenue recorded related to the June 1, 2017 to December 31, 2017 period. The OEB is expected to issue the final payment amounts order in the first half of 2018. Further details can be found under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

- Higher earnings of $377 million from the Services, Trading, and Other Non-Generation segment, primarily as a result of the gain on sale of OPG's head office premises and associated parking facility, a non-core asset of the business. A gain on sale of $283 million, which is net of tax effects of $95 million, was recognized in net income upon completion of the transaction in the second quarter of 2017. The sale was undertaken pursuant to a Shareholder Declaration and a Shareholder Resolution. Further details can be found under the heading, *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties*.
- Higher earnings of $24 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds), partially offset by an increase in accretion expense on the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

*Significant factors that reduced income before interest and income taxes:*

- Lower revenue of approximately $285 million, partially offset by a decrease in fuel expense of $31 million, reflecting lower electricity generation of 4.9 terawatt hours (TWh) from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, partially offset by an increase in generation from the Pickering GS. The increase in generation from the Pickering GS was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in fewer outage days at the station.
- Higher OM&A expenses of $77 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations and higher nuclear project expenses.
- Higher depreciation and amortization expense of $22 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in regulatory accounts, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in revenue in 2017, compared to 2016, but was largely offset by a decrease in the amortization expense related to regulatory account balances.

Net interest expense decreased by $25 million in 2017, compared to 2016, mainly due to a higher amount of interest costs capitalized for the Darlington Refurbishment project.

Income tax expense increased by $41 million in 2017, compared to 2016, primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred as regulatory assets in 2017.

## Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. Significant factors which contributed to the higher income during 2017, compared to 2016, are discussed above. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| *Income (loss) before interest and income taxes* | | |
| Regulated – Nuclear Generation | **57** | 4 |
| Regulated – Hydroelectric | **614** | 642 |
| Contracted Generation Portfolio | **300** | 282 |
| Total electricity generation business segments | **971** | 928 |
| Regulated – Nuclear Waste Management | **(150)** | (174) |
| Services, Trading, and Other Non-Generation [1] | **364** | (13) |
| Fair Hydro Trust | **-** | - |
| | **1,185** | 741 |

[1] Includes gain on sale of OPG's head office premises and associated parking facility. Refer to *Recent Developments – Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties* for further details.

## Electricity Generation

Electricity generation for 2017 and 2016 was as follows:

| *(TWh)* | **2017** | **2016** |
|---|---|---|
| Regulated – Nuclear Generation | **40.7** | 45.6 |
| Regulated – Hydroelectric | **30.7** | 29.5 |
| Contracted Generation Portfolio [1] | **2.7** | 3.1 |
| Total OPG electricity generation | **74.1** | 78.2 |
| Total electricity generation by other generators in Ontario [2] | **70.5** | 72.7 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

Total OPG electricity generation decreased by 4.1 TWh in 2017, mainly due to lower electricity generation of 4.9 TWh from the Regulated – Nuclear Generation segment. As expected, this was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was partially offset by an increase in generation from the Pickering GS, primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of outage days at the station, as well as higher electricity generation from the Regulated – Hydroelectric segment.

The higher electricity generation from the Regulated – Hydroelectric segment in 2017 was due to higher water flows primarily on the eastern Ontario river systems, net of forgone electricity generation as a result of SBG conditions, discussed below.

The lower electricity generation from the Contracted Generation Portfolio segment was primarily due to higher SBG conditions.

OPG's operating results are affected by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in

distribution networks, and the impact of conservation efforts in the province. Ontario's electricity demand as reported by the IESO was 132.1 TWh in 2017 and 137.0 TWh in 2016, which excludes electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric and certain nuclear stations and other grid-connected renewable resources. Baseload generation supply surplus in Ontario was more prevalent in 2017 than in 2016, mainly due to higher water flows and reduced electricity demand in the province during 2017. During 2017 and 2016, OPG lost 5.9 TWh and 4.7 TWh of hydroelectric generation due to SBG conditions, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions in 2017 and 2016 was offset by the impact of a regulatory variance account authorized by the OEB. Production forgone at OPG's regulated hydroelectric stations due to SBG conditions was 5.2 TWh in 2017 and 4.3 TWh in 2016. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

### Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The regulated prices authorized by the OEB for electricity generated from OPG's nuclear and regulated hydroelectric generating stations are discussed in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during 2017 was 7.1 cents per kilowatt hour (¢/kWh), compared to 6.9 ¢/kWh during 2016. The increase in this average sales price was primarily due to an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices, with an effective date of June 1, 2017. The increase was partially offset by the expiry of an OEB-authorized nuclear rate rider of $10.84 per MWh, on December 31, 2016, for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment during 2017 was 4.2 ¢/kWh, compared to 4.4 ¢/kWh during 2016. The decrease in this average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances, partially offset by the impact of an increase in revenue for the period June 1, 2017 to December 31, 2017 recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision. The rate riders that expired on December 31, 2016 were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances.

### Cash Flow from Operations

Cash flow provided by operating activities for 2017 was $944 million, compared to $1,817 million for 2016. The decrease was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow was also due to higher income tax instalments during 2017, compared to 2016.

The decrease in cash flow provided by operating activities was partly offset by lower contributions to the Used Fuel Segregated Fund in 2017. OPG's contributions to the Nuclear Segregated Funds are determined by reference plans under the Ontario Nuclear Funds Agreement (ONFA). Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to the most recent ONFA reference plan approved by the Province, effective January 1, 2017 (the 2017 ONFA Reference Plan). Therefore, no contributions to the Nuclear Segregated Funds are currently required starting in 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear

Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update.

### Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flow. The indicator is measured over a 12-month period. The FFO Adjusted Interest Coverage was 3.3 times for 2017 compared to 5.1 times for 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities net of changes to non-cash working capital balances, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in 2017 was primarily due to the change in the approach used to estimate the interest cost and service cost component of pension and OPEB costs prospectively adopted as of January 1, 2017. The change in the approach is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

### Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period. ROE Excluding AOCI for 2017 was 7.6 percent, compared to 4.2 percent for 2016. ROE Excluding AOCI increased for 2017, compared to 2016, primarily due to higher net income attributable to the Shareholder as a result of the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 and revenue related to the June 1, 2017 to December 31, 2017 period recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices. The increase in net income attributable to the Shareholder was partially offset by the impact of lower nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS.

### Enterprise Total Generating Cost per Megawatt-Hour

The Enterprise TGC per MWh was $50.66 for the year ended December 31, 2017, compared to $48.45 for the same period in 2016. The increase in Enterprise TGC per MWh was expected and primarily due to lower nuclear electricity generation as a result of the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures, partially offset by higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the station, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 to $5 per MWh lower for the year ended December 31, 2017. This sensitivity was calculated using the estimated incremental electricity generation and associated fuel cost that are expected to have had resulted in the absence of the refurbishment.

### Nuclear Total Generating Cost per Megawatt-Hour

The Nuclear TGC per MWh was $70.95 for the year ended December 31, 2017, compared to $62.30 for the same period in 2016. The increase in Nuclear TGC per MWh was expected and primarily due to the decrease in nuclear electricity generation primarily as a result of the Unit 2 refurbishment outage at the Darlington GS, and higher sustaining capital expenditures.

## Hydroelectric Total Generating Cost per Megawatt-Hour

The Hydroelectric TGC per MWh was $23.79 for the year ended December 31, 2017, compared to $25.49 for the same period in 2016. The improvement in the Hydroelectric TGC per MWh was primarily due to higher SBG-adjusted hydroelectricity generation reflecting higher water flows.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

## Recent Developments

OEB's Decision on OPG's Application for New Regulated Prices

The OEB's decision on OPG's May 2016 five-year application for new regulated prices for nuclear and regulated hydroelectric generation was issued on December 28, 2017, following a public hearing process. The OEB set an effective date for the new regulated prices of June 1, 2017. OPG had requested an effective date of January 1, 2017. The decision reflected the terms of an OEB-approved partial settlement agreement reached by OPG and intervenors on a limited set of issues in the first quarter of 2017 (Settlement Agreement). The decision included the OEB's findings with respect to ratemaking methodologies for the prescribed facilities, the basis for inputs into the hydroelectric incentive ratemaking formula, and the elements of the nuclear revenue requirement. Pursuant to the decision, for the first time since OPG's prescribed facilities became subject to rate regulation, the new prices will be determined using an incentive ratemaking methodology for the hydroelectric facilities and a custom incentive regulation framework for the nuclear facilities.

*Hydroelectric Facilities*

New regulated prices for the hydroelectric facilities for each of the years 2017 to 2021 will be determined by annually escalating the base regulated prices in effect prior to June 1, 2017, with some adjustments, using a formula equal to an industry-specific weighted inflation factor based on indices published annually by the OEB for use in incentive regulation formulas, less a stretch factor adjustment. The OEB accepted OPG's proposal to set the annual stretch factor adjustment at 0.3 percent. Based on the approved formula, the 2017 increase in the base regulated price for the regulated hydroelectric facilities is 1.4 percent as of June 1, 2017 and the 2018 increase is 0.9 percent as of January 1, 2018. For the 2019-2021 period, the base regulated price for the regulated hydroelectric facilities will be determined annually before the beginning of each year using the approved formula and inflation indices published by the OEB.

*Nuclear Facilities*

For the nuclear operations, a revenue requirement is determined for each of the years 2017 to 2021 based on the OEB-allowed level of OPG's forecast operating costs as reduced by a stretch factor amount, and a return on rate base determined using the OEB's generic prescribed return on equity rate and an OPG-specific deemed capital structure approved by the OEB. OPG has calculated that the findings of the OEB's December 2017 decision with respect to the forecast operating costs, rate base and deemed capital structure for the nuclear generating facilities will result in nuclear revenue requirements totalling approximately $15.9 billion over the full five years.

The OEB's findings with respect to the nuclear revenue requirement include approval for inclusion in rate base of in-service capital amounts related to the Darlington Refurbishment project of $5.5 billion by 2021, which comprises $4.8 billion forecast in the first quarter of 2020 upon return to service of Unit 2, $0.4 billion forecast for pre-requisite

projects excluding the Heavy Water Storage and Drum Handling Facility (HWSF) over the 2016-2021 period and $0.3 billion for pre-requisite projects placed in service prior to 2016. The OEB is expected to review the HWSF project as part of a future application. In the decision, the OEB concluded that it is appropriate to evaluate OPG's performance on the Darlington Refurbishment project at an overall level rather than by individual cost component, with recovery of any increases over the approved in-service amounts subject to a future prudence review. The revenue requirement impact of differences between the approved forecast in-service additions and the actual in-service additions related to the Darlington Refurbishment project will be recorded in the Capacity Refurbishment Variance Account authorized by the OEB pursuant to *Ontario Regulation 53/05* under the *Ontario Energy Board Act, 1998*. The $4.8 billion approved in-service amount upon return to service of Unit 2 includes expenditures incurred during the definition and planning phase of the project.

The OEB also approved recovery of OPG's requested forecast costs of approximately $292 million over the 2017-2021 period for activities to enable the commercial operation of the Pickering GS beyond 2020 and agreed to the inclusion of operating cost and generation impacts associated with planned continued operation of the station in 2021 in the nuclear revenue requirement. The differences between approved forecast enabling costs for continued operation of the Pickering GS and such actual amounts will be recorded in the Capacity Refurbishment Variance Account for future review and disposition by the OEB.

Excluding amounts that otherwise would have been recorded in OEB-authorized regulatory accounts for repayment to, or recovery from, customers in the future, the OEB's decision reduced OPG's proposed five-year nuclear revenue requirement by approximately $0.6 billion. The main adjustments made by the OEB included a reduction of $100 million per year to requested OM&A costs, a reduction of 10 percent per year to forecast non-Darlington refurbishment in-service capital additions entering rate base over the 2017-2021 period, an increase and expansion of the scope of the stretch factor for nuclear costs that further reduced the revenue requirement, and a rejection of OPG's request to increase the equity component of the existing deemed capital structure of 45 percent equity and 55 percent debt. The OEB increased the annual nuclear stretch factor to 0.6 percent and expanded its scope to include most of OPG's OM&A expenses incurred directly for, or allocated to, the nuclear facilities, as well as non-Darlington refurbishment in-service capital additions. The stretch factor is applied starting in 2018 and compounds in each year to 2021.

In accordance with *Ontario Regulation 53/05*, the nuclear revenue requirement continues to be adjusted by the amount of OPG's revenues, net of costs, from leasing the Bruce nuclear generating stations to Bruce Power. As directed by the OEB, OPG's revenues and costs related to the Bruce nuclear generating stations continue to be determined in accordance with US GAAP for the purposes of establishing the nuclear revenue requirement and remain subject to the Bruce Lease Net Revenues Variance Account established by the OEB in accordance with *Ontario Regulation 53/05*. This includes costs related to the portion of OPG's Nuclear Liabilities associated with the Bruce nuclear generating stations. The OEB's December 2017 decision maintained the previously approved cost recovery methodology for the Nuclear Liabilities for the prescribed facilities and for the Bruce facilities while directing OPG to file a future study examining such methodologies jurisdictionally and for OPG's assets specifically. The decision incorporated the impacts of the updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning as at December 31, 2016, including through the 2017 ONFA Reference Plan and the change in the Nuclear Liabilities recorded on December 31, 2016.

As proposed by OPG, the OEB set recovery of pension and OPEB costs in the nuclear revenue requirement on the basis of OPG's forecast cash payments for pension and OPEB plans, with differences between pension and OPEB accrual costs and cash payments continuing to be recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The regulatory treatment of pension and OPEB costs is discussed further under the heading, *OEB's Report on Regulatory Treatment of Pension and OPEB Costs*.

*Variance and Deferral Accounts*

The OEB's decision accepted all variance and deferral account balances proposed for recovery that were not already accepted as part of the Settlement Agreement, resulting in the approval to recover $305 million recorded in these accounts as at December 31, 2015, without adjustments. The Settlement Agreement provided for the continuation of all applicable existing variance and deferral accounts. In addition to the Rate Smoothing Deferral Account discussed below, the OEB established, as of the effective date of the new regulated prices, new variance and deferral accounts to record costs related to implementing CNSC's new fitness for duty requirements and to record differences between forecast and actual amount of Scientific Research & Experimental Development investment tax credits attributable to the nuclear facilities. CNSC's new fitness for duty requirements are discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

*Rate Smoothing*

Consistent with the requirements of *Ontario Regulation 53/05*, OPG's overall production-weighted regulated price will be smoothed, with a portion of the approved annual nuclear revenue requirements for the 2017-2021 period deferred in the Rate Smoothing Deferral Account for future collection.

As amended in March 2017, *Ontario Regulation 53/05* requires rate smoothing to be applied in a manner that makes changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The difference between the non-deferred portion of the nuclear revenue requirement, calculated by multiplying the nuclear regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection. The OEB's decision approved the nuclear production forecast as submitted by OPG.

Per the regulation, the Rate Smoothing Deferral Account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the Rate Smoothing Deferral Account on a straight line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project. OPG recognizes positive amounts deferred under rate smoothing as an increase in net regulatory assets and an increase to revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing are recorded as a decrease in net regulatory assets and a decrease to revenue.

*Draft Payment Amounts Order and Impact on Financial Results*

On January 17, 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017-2021 period, including a rate smoothing proposal, based on the December 2017 decision's findings. The rate smoothing proposal takes into account the near-term and future impacts on customers, while seeking to ensure that resulting nuclear regulated prices allow for sufficient cash flow to maintain the Company's investment grade credit rating and support availability of cost effective funding. Based on the OEB's direction, the draft payment amounts order also included proposed periods for recovery, through interim period shortfall rate riders, of the retrospective revenue shortfall amount for the period between June 1, 2017 and the implementation date of the new regulated prices based on proposed new regulated prices that would have been in effect during that period. The draft payment amounts order also included proposed recovery periods, through variance and deferral account rate riders, for regulatory account balances approved for recovery in this application.

To reflect management's best estimate of the impact of the OEB's decision, in the fourth quarter of 2017, OPG recorded net revenue of approximately $480 million for the June 1, 2017 to December 31, 2017 period, based on the draft payment amounts order. The revenue was recorded as an increase in regulatory assets for the June 1, 2017 to December 31, 2017 revenue shortfall period based on proposed new regulated prices, net of a regulatory liability recognized in relation to OPG's rate smoothing proposal. The OEB's approval of the final payment amounts order,

including the allocation of the approved revenue requirement between nuclear regulated prices and rate smoothing deferrals, is not expected to have a material impact on the amount of net revenue recorded in the fourth quarter of 2017 related to the OEB's decision. The OEB is expected to issue the final payment amounts order and implement new regulated prices in the first half of 2018.

Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2017 to May 31, 2017, OPG continued to record additions to the existing regulatory accounts for the nuclear and regulated hydroelectric facilities pursuant to the OEB's previous decisions and orders. These additions reflected differences between actual amounts and forecast amounts embedded in the regulated prices in effect prior to June 1, 2017.

In January 2018, OPG filed a motion asking the OEB to review and vary the effective date of the new regulated prices to January 1, 2017. The motion did not impact OPG's financial results for the year ended December 31, 2017.

Ontario's 2017 Long-Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 LTEP that outlines the Province's plans for the future development of Ontario's electricity system. The 2017 LTEP focuses on the affordability, reliability and flexibility of a clean energy supply in the province. The 2017 LTEP replaces the previous LTEP issued in 2013.

As it relates to the supply of electricity, the 2017 LTEP recognizes the refurbishment of Ontario's nuclear generating stations as the most cost-effective option for producing emission-free baseload generation to meet Ontario's needs and reaffirms the Province's support for the refurbishment of the four units at the Darlington GS and the six units at the Bruce generating stations, subject to the principles established in the 2013 LTEP. The 2017 LTEP also recognizes the value to customers of continuing to operate the Pickering GS until 2024, as planned. With respect to hydroelectric electricity generation, the 2017 LTEP highlights the opportunity to continue to invest in optimizing existing hydroelectric facilities, noting that pumped hydroelectric storage could play an important role in the reliability of the electricity system.

Additionally, the 2017 LTEP discusses the potential impact of a number of innovative technologies on the future of the electricity system. Among others, these include the increased electrification of the transportation sector, the emergence of energy storage, and the opportunity for Ontario to foster nuclear innovation technologies. OPG continues to assess how best to capitalize on potential business opportunities in these and other areas. The 2017 LTEP also recognizes the importance of Indigenous peoples' continuing role in shaping Ontario's energy planning, projects and policies. Over the past several years, OPG has partnered with Indigenous communities on a number of generation-related developments and other joint projects and will continue to seek additional opportunities to dialogue with and seek involvement of Indigenous peoples in the electricity industry's future.

Darlington Refurbishment

In October 2016, OPG commenced the refurbishment of the first Darlington GS unit, Unit 2, as part of the Darlington Refurbishment project. The de-fuelling of the reactor and islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, were completed in the first half of 2017.

The disassembly of reactor components commenced in the third quarter of 2017, with the removal of feeder tubes completed in September 2017. The removal of fuel channel assemblies commenced in October 2017. The removal of pressure tubes as part of the fuel channel assemblies was completed in March 2018, with the removal of calandria tubes currently in progress. The removal of all reactor components is expected to be completed in mid-2018.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. The completion of the HWSF has been delayed due to construction challenges, with construction activities suspended for a portion of 2017. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule.

The cost of the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking into account the execution performance of the Unit 2 refurbishment and the cost to complete the HWSF, the overall Darlington Refurbishment project continues to track to the $12.8 billion budget.

On November 21, 2017, the Financial Accountability Office of Ontario issued a report, "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses the impact of OPG and Bruce Power's respective nuclear refurbishments on customers and the Province based on mechanisms in place for the recovery of the costs to refurbish and subsequently operate these nuclear stations. The report concludes that refurbishment of the four units at the Darlington GS and the six units at the Bruce nuclear generating stations provides the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements.

In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of the second unit at the Darlington GS, Unit 3. OPG continues to progress planning and procurement activities for the Unit 3 refurbishment in accordance with the refurbishment project schedule.

The Darlington Refurbishment project is discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The CNSC publishes an annual Regulatory Oversight Report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report, giving both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

Ontario's Fair Hydro Plan

On March 2, 2017, the Province announced the Fair Hydro Plan aimed at reducing electricity bills for residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment costs over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the Fair Hydro Act received Royal Assent and the associated general regulation came into force in June 2017. The Act established a framework under which the costs and benefits associated with the Government of Ontario's clean energy initiatives are to be allocated between present and future consumers of electricity under the Fair Hydro Plan. The general regulation provides details on the structural, operational and financial elements required to implement the Fair Hydro Plan.

Pursuant to the Act, effective May 1, 2017, the IESO began to defer a portion of the Global Adjustment costs. The Act allows the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire an Investment Interest from the IESO.

In November 2017, OPG's Board of Directors provided its final approval regarding OPG's involvement as the Financial Services Manager under the Act on commercial terms following the fulfilment of all conditions the Board of Directors established in May 2017. Accordingly, the Fair Hydro Trust was established as the financing entity contemplated by the Act in December 2017. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG in order to protect the

Company's assets and operations.

In order for the Trust to finance the acquisition of Investment Interest from the IESO, it will incur senior debt from capital markets and subordinated debt from OPG. The Trust's investment will attract financing amounts and other related fees, which, under the general regulation, will be payable by the IESO as carrying costs until July 2021 and by Specified Consumers through the Clean Energy Adjustment to be invoiced by local distribution companies commencing in May 2021, with the three-month overlap in 2021 intended to cover the billing and collection lag from the introduction of the Clean Energy Adjustment. The Clean Energy Adjustment payments by Specified Consumers will be remitted to the Trust through the IESO. The carrying costs include all financing and third-party costs other than repayment of debt principal.

Concurrent with every issuance of the Trust's senior notes, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt, with 44 percent to be provided by the Province through equity injections in OPG and five percent to be provided by OPG. The subordination level may vary over time, but must be at least equal to 35 percent of the Trust's total outstanding debt. Through OPG's control over the key activities of the Trust and its obligation to absorb losses through ownership of the Trust's subordinated debt, the Company consolidates the financial results of the Trust in accordance with US GAAP.

On December 21, 2017, the Trust purchased its first tranche of Investment Interest from the IESO in the amount of approximately $1.18 billion. Fifty-one percent of the funding requirement or $601 million was financed by the Trust through a revolving warehouse facility ranked as senior notes, and the remaining 49 percent was funded through the issuance of short-term subordinated debt to OPG. The Investment Interest has been classified as a financing receivable on OPG's consolidated balance sheet.

OPG's purchase of the subordinated debt issued by the Trust was funded through the following sources:

- The Province provided 44 percent of the funding requirement, or $519 million, through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A shares at a price of $42.46 per share. The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of Class A shares. Refer to Note 14 of OPG's 2017 audited consolidated financial statements for further details on the nature of the Class A shares; and
- OPG provided five percent of the funding requirement or $60 million.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued in December 2017. In March 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, with 51 percent of the funding being sourced from the revolving warehouse facility, 44 percent through an equity injection from the Province, and five percent from OPG.

Refer to the section, *Liquidity and Capital Resources* under the heading, *Financing Activities* for further details on the Trust's financing arrangements.

OEB's Report on Regulatory Treatment of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report established the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The report also provides for the establishment of a generic variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments

made by a utility in respect of pension and OPEB plans. Carrying charges on this differential are to be assessed at the OEB's prescribed interest rate, on a prospective basis from the effective date of the new variance account. For OPG, this differential will include amounts going back to November 1, 2014, with the charges calculated on the portion of the differential that has been recovered through regulated prices. None of this differential has been recovered to date. The prescribed interest rate is set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield.

The OEB's September 2017 report and the OEB's December 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, until such time as the OEB decides on the approval and implementation of resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. The OEB's report did not impact OPG's financial results for the year ended December 31, 2017.

The Company recognizes the amount set aside in the Pension & OPEB Cash Versus Accrual Differential Deferral Account as a regulatory asset. As at December 31, 2017, the regulatory asset had a balance of $614 million. Consistent with the expectations set out in the OEB's December 2017 decision, in 2018, OPG plans to file an application with the OEB requesting disposition of the Pension & OPEB Cash Versus Accrual Differential Deferral Account balance and the balances accumulated since December 31, 2015 in other regulatory accounts, as well as approval to resume the accrual basis of accounting as the recovery method for pension and OPEB amounts in future determinations of base regulated prices.

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017, with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income in the second quarter of 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading, and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014* (Trillium Trust Act), OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds to be transferred into the Consolidated Revenue Fund is expected to approximate the after-tax gain on sale. The transfer is expected to take place as early as in the first quarter of 2018, through a special dividend authorized by OPG's Board of Directors in March 2018.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser, with the sale scheduled to close in March 2018. An estimated after-tax gain on sale of approximately $200 million is expected to be recognized in net income upon completion of the transaction. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the Trillium Trust Act, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Trillium Trust Act, into the Province's Consolidated Revenue Fund. OPG anticipates the amount of designated proceeds transferred into the Consolidated Revenue Fund to approximate the after-tax gain on the sale. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses.

## CORE BUSINESS, STRATEGY, AND OUTLOOK

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of its customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business expansion opportunities to the benefit of the Shareholder.

OPG's four key strategic imperatives are as follows:

- Operational Excellence
- Project Excellence
- Financial Strength
- Social Licence.

### Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Workplace Safety and Public Safety

Workplace safety and public safety are fundamental core values at OPG. OPG is committed to operating all of its facilities in a safe, secure, and reliable manner that minimizes risks to a reasonably achievable level. Safety is an overriding priority in all activities performed at OPG's generating and other facilities, and all employees and contractors are expected to conduct themselves in a manner that ensures workplace safety and public safety in line with the Company's safety culture.

In the area of workplace safety, OPG is committed to achieving excellent performance through continuous improvement and a strong safety culture, with the ultimate goal of zero injuries. OPG utilizes an integrated health and safety management system and a set of operational risk control procedures to ensure continued monitoring of health and safety performance and to support continuous learning and improvement in this area. Over the past five years, OPG has repeatedly stood in the top quartile of its comparator Canadian electrical utilities in various safety performance metrics.

Workplace safety performance is measured using two primary indicators at OPG, All Injury Rate (AIR) and Accident Severity Rate (ASR). OPG's AIR and ASR results for employee workplace safety were as follows for the year ended December 31:

| | 2017 | 2016 |
|---|---|---|
| AIR *(injuries per 200,000 hours worked)* | **0.48** | 0.56 |
| ASR *(days lost per 200,000 hours)* | **3.57** | 2.59 |

In 2017, OPG's AIR improved from 2016 and was the third-best performance year in the Company's history. For those employee injuries that caused lost time from work, the total time lost from work in 2017 was greater than the previous year. OPG's analysis of the underlying safety events indicated that major contributors to the injuries and near misses included inadequate situational awareness and attention to detail, and suboptimal risk-based decisions, rather than missing or inadequate standards or programs. OPG continues to implement a number of initiatives to target the injury trends based on the analysis of the safety events, with a focus on the use of human performance tools including increased field supervisory oversight, situational awareness, communication, and procedural use and adherence.

In order to strengthen its safety performance, OPG continues to progress an organization-wide "iCare Enough to Act" initiative launched in 2016 to renew employees' commitment to their own and each other's safety and well-being.

Approaches to supervisory oversight, communication and safe work planning are being modified and updated to further strengthen safety as a foundational element of the Company's values-based culture.

Contractors are required to conduct work safely at OPG sites. In support of this requirement, OPG utilizes an independent contractor pre-qualification process, provides on-site safety support for many of its major projects, and works with contract partners to improve their health and safety programs to meet OPG's requirements. In the past nine years, OPG has consistently shown a Construction Contractor AIR that is markedly better than the Infrastructure Health and Safety Association Contractor AIR, a metric of construction contractor safety performance across Ontario. OPG has maintained this performance while engaging in the refurbishment of the Darlington GS, one of the largest infrastructure projects in Canada. The hours worked by contractors in 2017 were the largest in OPG's history, largely attributable to this project.

OPG continues to maintain a strong focus on the nuclear safety program and to invest in nuclear safety systems. To ensure continued public safety, radiation exposure to members of the public resulting from the operation of OPG's nuclear generating stations is estimated on an annual basis for individuals living or working near the stations. The annual dose to the public resulting from operations of each nuclear facility is expressed in microsieverts (μSv), which is an international unit of radiation dose measurement. For 2016, the annual public doses resulting from the Darlington GS operations and the Pickering GS operations were 0.6 μSv and 1.5 μSv, respectively, which is less than 0.1 and 0.2 percent of the annual legal limit of 1,000 μSv, respectively. While the public doses from OPG's nuclear operations for the 2017 operating year will not be finalized until the second quarter of 2018, they are not expected to differ significantly from the 2016 levels.

In June 2016 and August 2016, the CNSC released sampling results from its independent environmental monitoring program, which confirmed that the public and the environment around OPG's nuclear generating stations continued to be safe. In September 2017, the CNSC issued an executive summary of its 2016 annual report on the safety performance of Canada's nuclear power plants, which gave both the Pickering GS and the Darlington GS the highest possible safety rating of "Fully Satisfactory". For further details, refer to the CNSC safety rating discussion in the section, *Highlights* under the heading, *Recent Developments – Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS*.

OPG remains committed to high standards of public safety on waterways around hydroelectric generating stations and dams, and continues to make investments in waterway and dam safety upgrades. The Company's practices in this area are routinely reviewed by an independent panel comprised of internationally recognized experts, who have concluded that OPG's dam safety program is industry leading in a number of areas. During 2017, OPG continued its water safety campaign with a series of public service announcements illustrating the danger of water near hydroelectric dams and hydroelectric generating stations.

Electricity Generation Production and Reliability

Key strategic initiatives in support of operational excellence, specific to each of OPG's core generating operations, are discussed below. Generation and reliability performance for 2017 is discussed by operating segment in the section, *Discussion of Operating Results by Business Segment*.

*Nuclear Operations*

OPG is pursuing a number of strategic initiatives aimed at the continued safe and reliable operation of the Pickering GS and targeting top performance at the Darlington GS.

OPG's objective is to maximize the safe and reliable operating life of the Pickering units. As announced in 2016 and approved by the Province, OPG is continuing to execute on a plan to extend safe and reliable operation of the Pickering GS to 2024. In addition to providing Ontario with a clean, reliable source of baseload electricity during nuclear unit refurbishments at the Darlington GS and the Bruce nuclear generating stations, extending operations at the Pickering GS will provide continued employment for over 3,000 employees at OPG and help to reduce

approximately 17 million tonnes of carbon dioxide emissions, which is equivalent to removing approximately 3.4 million cars from Ontario's roads.

OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This current licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The requested licence term spans the planned extended commercial operation period, through to the planned period of de-fuelling, de-watering and beginning to place the station in a safe storage state in 2028. In support of the licence renewal, OPG undertook a Periodic Safety Review (PSR), a comprehensive assessment of the station's design and operation to confirm that there is a high level of safety throughout the operating life and to determine what reasonable and practical enhancements can be made to further improve safety. The PSR also includes a component condition assessment of the station to identify the work required to support the station's continued operation. The PSR has confirmed that extending commercial operation of the Pickering units will continue to pose minimal risk to the health, safety and security of workers, the public and the environment. The final major component of the PSR was submitted to the CNSC in November 2017. The CNSC's review of the PSR submission and licence application is in progress. Based on the evidence and documentation submitted to the CNSC, OPG believes it is well positioned to obtain a licence renewal that would support its extended operations plan for the Pickering GS to 2024.

As part of the plan to extend Pickering operations, OPG has been continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. In the fourth quarter of 2017, OPG has confirmed that technical assessments completed to date provide sufficient confidence in the programs and provisions in place to assure fitness-for-service of fuel channel components in line with the station's planned extended commercial operation period. This evaluation was consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the CNSC in 2017, discussed below. Taking these factors into account, OPG revised the accounting end-of-life assumptions for the Pickering GS from December 31, 2020 for all units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8, effective December 31, 2017. OPG continues to execute the work required for the planned extended commercial operation of the station, including plant modifications and other work as identified through the PSR, station reliability initiatives, and equipment component inspections.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. Excluding the impact of regulatory accounts, the change in the accounting end-of-life assumptions is expected to decrease depreciation expense by approximately $77 million in 2018, including the impact of the associated change in the nuclear asset retirement obligation (ARO) recorded as of December 31, 2017. Regulatory accounts, including a new deferral account proposed by OPG in an application to the OEB on December 29, 2017, are expected to offset the decrease in depreciation expense, beginning on January 1, 2018. Pending its review of this application, the OEB issued an order on January 31, 2018 establishing the proposed deferral account on an interim basis to allow OPG to begin recording amounts in the account as of January 1, 2018. The OEB's final decision on the application is expected later in 2018. The change in the nuclear ARO as of December 31, 2017 is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*.

OPG's nuclear operations are regularly benchmarked against top performing nuclear facilities around the world. This allows OPG to identify, develop and implement initiatives to further improve performance. In September 2016, OPG hosted a team of experts from the International Atomic Energy Agency (IAEA) at the Pickering GS to conduct a standard Operational Safety Review Team mission. The team conducted an in-depth review of performance and adherence to international safety standards. In the second quarter of 2017, the IAEA's Operational Safety Review Team released the final report and confirmed that the Pickering GS demonstrates a strong commitment to safety. In December 2017, OPG hosted a World Association of Nuclear Operators (WANO) peer evaluation for the Pickering GS, which focused on the safe and reliable operation of the station while evaluating the plant material condition and functional and cross-functional areas of the station. The results of the evaluation showed that the Pickering GS

sustained its strong rating while demonstrating significant improvement since the last review, resulting in its best ever WANO peer review.

OPG remains focused on improving reliability and increasing electricity generation output from its nuclear fleet. This includes improving equipment reliability, optimizing outages, implementing integrated asset management planning and enhancing maintenance programs. Improved equipment reliability generally results in fewer generation interruptions. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, and are designed to ensure that equipment is performing safely and reliably. Execution of this and other outage work continues to be a high priority. As part of its commitment to operational excellence, OPG continues to focus on improving the planning, execution, monitoring, and reporting of outage work.

OPG continues to make investments in the performance of the Pickering GS, with a focus on improving plant reliability and maximizing the value of the asset over its remaining life through implementing equipment modifications and fuel handling reliability improvements, reducing equipment maintenance backlogs, and completing critical and high priority work. OPG also continues to make investments in the Darlington GS necessary to sustain safe and reliable operations for the next three decades, aimed at positioning the station for industry-leading operating and cost performance in the longer term. This includes investments in life cycle and aging management projects, facility upgrades and work in support of regulatory commitments.

Delivering solutions that provide the best combination of safety, cost and effectiveness, as well as establishing challenging financial targets based on comprehensive benchmarking and taking into account the operating environment of the nuclear stations, continues to be a vital part of OPG's strategy to improve the performance of the nuclear business unit. Financial and staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety and reliability are not compromised.

In 2016, OPG submitted applications with the CNSC seeking a ten-year licence renewal for the Western Waste Management Facility (WWMF), located at the Bruce generating stations' site, to May 31, 2027, and a ten-year licence renewal for the Pickering Waste Management Facility (PWMF) to August 31, 2028. The licence renewal applications were presented to the CNSC at public hearings in April 2017. On May 30, 2017, the CNSC announced that the WWMF licence was renewed for a ten-year period and will be valid until May 31, 2027. On February 7, 2018, the CNSC announced that the PWMF licence was renewed for a ten-year period and will be valid until August 31, 2028.

In 2017, the CNSC approved regulatory document *REGDOC 2.2.4 – Fitness for Duty – Managing Alcohol and Drug Use* for use at Canadian nuclear power plants. This document sets out requirements for managing fitness for duty of workers in relation to alcohol and drug use at high-security sites, including for-cause alcohol and drug testing for workers in positions identified as safety-sensitive or safety-critical, and random alcohol and drug testing for workers holding safety-critical positions. OPG intends to enhance its existing Fitness for Duty program to comply with these new requirements. OPG is working with its partners in the Canadian nuclear industry to develop a program suitable for Canada and its workers.

Pursuant to the *Emergency Management and Civil Protection Act*, a Provincial agency, Office of the Fire Marshal and Emergency Management (OFMEM), is required to periodically update the Provincial Nuclear Emergency Response Plan (PNERP). In 2016, the CNSC advised the OFMEM to consider more severe accidents in the update to the PNERP. In December 2017, the Province approved the updated PNERP Master Plan. The changes include a new 20-km Contingency Planning Zone around the Pickering and Darlington nuclear generating stations, which will improve protective actions for the public. The development of an Implementing Plan for the Pickering GS is in progress, with an expected approval by the Province by mid-2018. An Implementing Plan for the Darlington GS is expected to be drafted once the Implementing Plan for the Pickering GS is completed. The updated PNERP is not expected to have a significant impact on OPG.

*Hydroelectric Operations*

The objectives of OPG's hydroelectric operations include operating and maintaining the generating facilities in a safe, efficient and cost-effective manner, while increasing the output from the facilities and pursuing opportunities to increase the fleet's capacity. OPG aims to increase the facilities' output by improving operational flexibility, enhancing reliability, optimizing outage planning and, subject to water conditions, increasing availability to meet electricity system demand. OPG continues to evaluate and implement plans to increase capacity, maintain and improve operational performance, and extend the operating life of its hydroelectric generating assets.

OPG's hydroelectric operations are regularly benchmarked against peer utilities in North America. Based on 2016 data, 19 of OPG's 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for unit energy costs. This group of 19 facilities represents 94 percent of the energy delivered from the regulated hydroelectric fleet. Similarly, 18 of the 25 large regulated hydroelectric facilities benchmarked in the top two quartiles for Hydroelectric Availability based on 2016 data. OPG continues to pursue innovation and technology-based improvements in its asset management and equipment maintenance strategies in order to increase reliability and further reduce costs of the hydroelectric fleet.

As part of OPG's ongoing strategy to reduce costs and increase operational efficiency, the operations of the Company's hydroelectric and thermal assets were previously combined into one organization, with five regional operations groups. In 2017, OPG reduced the number of regional operations groups to four, by integrating the Central Operations work centres into three of the other existing groups. In addition, during the third quarter of 2017, OPG opened an amalgamated control room located at the R.H. Saunders hydroelectric GS, combining the Chenaux and Saunders control rooms. The amalgamated control room will control all operational activities at the ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.

OPG's plans for its existing hydroelectric generating stations are accomplished through multi-year capital investment and other programs, including replacements and upgrades of turbine runners, and refurbishment or replacement of existing generators, transformers, and control systems. The aim of OPG's runner replacement and upgrade program is to increase hydroelectric station capacity by leveraging efficiency enhancements in runner design. Where economic and practical, OPG also pursues opportunities to refurbish, expand or redevelop its existing hydroelectric stations. Over the next four years, OPG plans to increase the total capacity of its hydroelectric generating fleet by approximately 100 MW, which, in addition to the runner replacement and upgrade program, includes the Ranney Falls GS project and the planned Sir Adam Beck I GS frequency conversion project. OPG is also planning to repair, rehabilitate, or replace a number of aging civil hydroelectric structures. The Ranney Falls GS project is discussed under the heading, *Project Excellence – Ranney Falls Hydroelectric GS*.

As part of its commitment to operational excellence, OPG continues to make investments in its existing hydroelectric generating fleet. During 2017, OPG continued to execute a number of projects, including:

- Completion of the overhaul and upgrade of Unit 10 of the Sir Adam Beck 1 GS, which increased the station's capacity by 6 MW
- Continued work on the overhaul and rehabilitation of Unit 1 of the Sir Adam Beck Pump GS to ensure reliable unit operation for approximately the next 20 years, which was completed in March 2018
- Completion of the replacement of the Shebandowan Lake Control Dam at the Kakabeka Falls GS, which will maintain structural integrity and enhance dam safety for another 100 years
- Continued work on the overhaul and upgrade of Unit 1 of the Harmon GS, which was completed in February 2018
- Continued work on the overhaul and upgrade of Unit 2 of the DeCew Falls GS, with turbine and generator rehabilitation and upgrade of protection and control systems completed during the year, and commencement of the overhaul and upgrade of Unit 2 of the Little Long GS in the fourth quarter of 2017

- Continued work on the overhaul and rehabilitation of Unit 2 of the Lower Notch GS, with generator rehabilitation completed during the year, and commencement of the overhaul and rehabilitation of Unit 6 of the Sir Adam Beck Pump GS in the fourth quarter of 2017
- Commencement of definition phase work for the Water Conveyance System project to rehabilitate the Sir Adam Beck 1 GS canal and associated structures, to ensure their continued safe and reliable operations for approximately the next 50 years.

In 2018, OPG plans to commence execution of several major sustaining projects across the hydroelectric fleet, including the overhaul and upgrade of Unit 5 of the Sir Adam Beck 1 GS, the rehabilitation of Caribou Falls Block Dam No. 2, and automatic sluicegates system replacement at the Whitedog Falls GS. Definition phase activities on several other major projects are also expected to commence in 2018, including frequency conversion of Units 1 and 2 of the Sir Adam Beck 1 GS and the overhaul and upgrade of the R.H. Saunders GS units.

*Thermal Operations*

OPG's thermal operations consist of biomass-fuelled generating units at each of Atikokan GS and Thunder Bay GS, and the oil/gas dual-fuelled Lennox GS.

These stations, which operate as peaking facilities under their respective energy supply requirements, provide Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements and enable the system to accommodate the expansion of Ontario's renewable generation portfolio. The continued operation of these stations will continue to provide Ontario with over 2,000 MW of peaking generation capacity.

OPG's biomass-fuelled generating units are among the world's leading in their innovation. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass, while the Thunder Bay GS unit uses advanced biomass that is thermally treated to allow it to be stored outdoors and withstand exposure to the weather.

Former thermal stations that are no longer available to generate electricity are included in the Services, Trading, and Other Non-Generation segment once they are removed from service. This includes the Lambton GS and Nanticoke GS sites, which ceased operations in 2013. Over 2015 and 2016, OPG announced that these stations would be decommissioned safely, securely and in an environmentally responsible manner. The costs of the decommissioning are charged to a previously established decommissioning provision.

During 2017, OPG substantially completed the demolition of the Nanticoke coal yard equipment and structures and issued a contract for the demolition of the Nanticoke powerhouse and associated structures. In the fourth quarter of 2017, the demolition contractor had been mobilized to prepare for the removal of the powerhouse and associated structures and initiated the preparatory work for the demolition of the stacks. The demolition of the stacks took place in February 2018. A competitive bidding process for the demolition of the Lambton GS is in progress, with a contract for the removal of the powerhouse and associated structures expected to be issued during 2018. The decommissioning plan for the Nanticoke GS accommodates the construction and operation of the Nanticoke solar facility. The Nanticoke solar facility is discussed under the heading, *Project Excellence – Nanticoke Solar Facility*.

An update of the asset retirement obligations related to the Nanticoke and Lambton sites has been completed. For a discussion of the revaluation of the fixed asset removal liability for the thermal stations as at December 31, 2017, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligations*.

Environmental Performance

OPG is committed to meeting compliance obligations, including any environmental commitments that it makes, with the objective of surpassing these compliance obligations where it makes business sense. OPG's Environmental Policy commits the Company to:

- maintain an ISO 14001-registered environmental management system (EMS)

- work to prevent or mitigate adverse impacts on the environment with a long-term objective of continual improvement
- strive to be a leader in climate change mitigation
- manage sites in a manner that strives to maintain, or enhance where it makes business sense, significant natural areas and associated species of concern.

In 2017, OPG maintained the ISO 14001 registration of its company-wide EMS. Within the EMS, OPG has planning, operational control, and monitoring programs to manage the Company's positive and negative impacts on the environment. Significant environmental aspects of OPG's operations include: spills, chemical and thermal emissions to water, water flow and level changes, radiological emissions, low and intermediate level radioactive waste (L&ILW), displacement of fossil fuels, enhancement and disruption of wildlife habitat, and fish impingement and entrainment. Further details regarding OPG's environmental risks can be found in the section, *Risk Management* under the heading, *Environmental Risk*.

Environmental performance targets are set as part of the annual business planning process. These targets are based on past performance and external benchmarking to promote continuous improvement. OPG met or outperformed its 2017 targets for spills, environmental infractions, carbon-14 emissions to air, and L&ILW. Targets for tritium emissions to air and water were not achieved due to equipment performance issues; however, emissions remained less than one percent of the regulatory limit. There were no significant environmental events during 2017.

In 2016, the Government of Ontario passed the *Climate Change Mitigation and Low-Carbon Economy Act, 2016* and the associated *Cap and Trade Program Regulation*. The legislation provides the foundation for regulating greenhouse gas (GHG) emissions in Ontario and establishes a cap and trade program, with the first compliance period being from January 1, 2017 to December 31, 2020.

The cap and trade program is a market mechanism intended to give Ontarians an incentive to reduce GHG emissions by putting a price on carbon. OPG has an internal program to meet its GHG emissions compliance obligations. With OPG's low GHG emitting fleet, these obligations do not have a material financial impact on the Company.

OPG monitors actions being taken by the Government of Ontario and the Government of Canada to reduce GHG emission levels and transition to a low-carbon economy. In support of efforts to mitigate climate change, the Company continues to evaluate and implement plans to increase the generation capacity of its hydroelectric fleet where economical, invest in other low-carbon technologies, including nuclear innovation and energy storage, and take a leadership role in the electrification of Ontario's transportation sector.

OPG has developed biodiversity management plans that identify priority natural areas, conservation goals, threats, and proposed actions to sustain biodiversity at the Company's operating sites. To maximize benefits and manage impacts, initiatives include biodiversity monitoring, site naturalization, habitat creation, and control of invasive species.

OPG works with community partners to support regional ecosystems and biodiversity across Ontario. In 2017, OPG continued efforts to protect and restore habitat, promote biodiversity education and awareness, and help the recovery of species at risk. In November 2017, OPG's biodiversity program was recognized by the Canadian Electricity Association with the 2017 Sustainable Electricity award for Commitment to Continuous Performance Improvement.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change (MOECC), Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report and the Company's Environmental Policy, which are available on the Company's website at www.opg.com.

Improving Efficiency and Reducing Costs

As part of its commitment to operational excellence, OPG remains strongly focused on reducing costs by pursuing sustainable efficiency and productivity improvements across operating business units and support functions, while ensuring that there is no adverse impact on the safety, reliability and environmental sustainability of the Company's operations. Building on significant efficiencies achieved since 2011 under a more scalable, centre-led organizational model, this includes streamlining of processes, simplifying governance, upgrading technology, optimizing service delivery models, and continuing to leverage attrition to achieve human resource targets aligned with business requirements. Strategies to improve cost performance and organizational capability are being implemented at the enterprise and business unit level. These strategies are supported by continuing efforts to embed an outcomes-driven culture that reinforces cost effectiveness, efficiency and organizational agility as part of business decision-making.

OPG is proceeding with an enterprise-wide process to evaluate the impact of the eventual shutdown of the Pickering GS on the Company's operating cost structure. This multi-year initiative, known as OPG25, involves identifying and implementing a coordinated set of plans and targets to ensure the optimization of the Company's longer-term operating model, business strategies and organizational design between now and the planned end of Pickering commercial operation in 2024. The overall aim of the initiative is to ensure ongoing cost effectiveness of the Company's operations after the eventual shutdown of the Pickering GS and to mitigate the cost impacts associated with the shutdown. Through this work and a continued focus on productivity enhancements, OPG expects to deliver increased value to customers and achieve improvement in outcomes of future applications for regulated prices under the OEB's incentive regulation framework.

In 2017, OPG launched a strategy to accelerate the pace of digital transformation across the enterprise. The strategy is focused on making investments to modernize information technology infrastructure, enhance mobility, connectivity and field and office productivity, and improve equipment reliability and station performance through data management and data analysis. The goal of the strategy is increase operational efficiency, reduce operating costs and help to enable optimization initiatives in support of OPG25.

People and Culture

A well trained and engaged workforce is fundamental to the achievement of OPG's strategic imperatives. To succeed in a demanding business environment, OPG is focused on building a diverse, healthy, engaged workforce and fostering a culture of collaboration, accountability and innovation. OPG also continues to communicate and implement the values and behaviours expected from its employees in order to maintain a strong focus on safety, performance excellence, continuous improvement, and corporate citizenship.

The Company continues to focus on improving the capability of its workforce through leadership development, knowledge management, diversity and inclusion programs, and hiring in critical areas. Ability to secure the right talent mix in order to effectively meet the Company's immediate and longer term business needs on a timely basis is supported through workforce planning, resourcing and on-boarding strategies, both to acquire external talent into the organization and to develop existing employees. The goal of workforce planning and resourcing strategies is to ensure that the Company has a diverse workforce with the right skill set and capability for the safe and effective operation of the generating facilities and successful delivery of major projects, including the Darlington Refurbishment. These strategies take into account changes in anticipated staffing requirements leading up and subsequent to the end of planned commercial operation of the Pickering GS and the period to de-fuel, de-water and place the station in a safe storage state after shutdown. The end of commercial operation at the Pickering GS is expected to lead to a significant reduction in OPG's workforce.

As part of the strategy to develop and engage employees and to build leadership talent in support of the Company's long-term success, OPG has an active succession planning program with a focus on accelerating development. This includes a company-wide high-potential leadership development program for qualified internal candidates. This

14-month cross-functional, competitive-entry program is designed to identify and develop candidates for future leadership positions while they are relatively early in their careers. OPG also has a talent management monitoring process to proactively assess staffing risks, challenges and opportunities.

Electricity generation involves complex technologies that require highly skilled and trained workers. Many positions at OPG have significant educational prerequisites and rigorous requirements for continuous training and periodic requalification. In addition to maintaining its internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners and educational institutions to meet the required level of qualification. Training delivery models are evaluated for effectiveness and efficiency.

Effective January 1, 2017, OPG implemented an Executive Compensation Program that is compliant with *Ontario Regulation 304/16: Executive Compensation Framework*, introduced in September 2016. The regulation sets out how all employers designated under the *Broader Public Sector Executive Compensation Act, 2014*, including OPG, must establish and post compensation programs for executives. The program must include the compensation philosophy, salary and performance-related pay caps, comparative analysis details, and a description of other elements of compensation. OPG's Executive Compensation Program, which applies to employees at the Vice President level and higher, is designed to provide compensation that is at the 50$^{th}$ percentile of the market and is focused on at-risk, performance based pay. The program aims to enable OPG to attract, align and retain the executive talent critical to delivering Shareholder and customer value, while ensuring continued safe and reliable operations. OPG's Executive Compensation Program was not affected by the two regulations amending *Ontario Regulation 304/16* that were released in 2017, as the program continues to be subject to the original regulation's requirements.

### Project Excellence

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG also continues to plan and execute maintenance and capital improvement projects related to its existing assets. OPG strives for excellence in the planning and delivery of all projects across the Company.

OPG's vision for project excellence is to be an industry leader in project management capability and performance. As part of its commitment to project excellence, OPG continues to enhance and streamline its approach to project planning and execution, with the goal of delivering all projects safely, on time, on budget and with high quality. Achieving project excellence at OPG involves, among other things, implementing a common, scalable project delivery model across all business units, establishing qualified project management teams, optimizing contracting strategies, engaging qualified and experienced vendors, and effectively monitoring and controlling performance.

The status updates for OPG's major projects as of December 31, 2017 are outlined below.

| Project | Capital expenditures | | Approved budget | Expected in-service date | Current status |
|---|---|---|---|---|---|
| *(millions of dollars)* | Year-to-date | Life-to-date | | | |
| Darlington Refurbishment | 1,249 | 4,434 | 12,800 [1] | First unit - 2020<br>Last unit - 2026 | All Unit 2 feeder tubes were removed safety in the fourth quarter of 2017 and the removal of fuel channel assemblies is in progress. Construction activities on the HWSF recommenced in the fourth quarter of 2017. Planning and procurement activities for the refurbishment of Unit 3 are continuing. The overall project is tracking on schedule and on budget. |
| Peter Sutherland Sr. Hydroelectric GS | 41 | 277 | 300 | 2017 | The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress. |
| Sir Adam Beck Pump GS Reservoir Refurbishment | 3 | 49 | 58 | 2017 | The refurbishment was completed and the reservoir was returned to service in February 2017, ahead of the originally planned in-service date and below the approved budget. |
| Ranney Falls Hydroelectric GS | 25 | 28 | 77 | 2019 | Excavation has been completed and construction is continuing in the expanded forebay, powerhouse and spillway area. Concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project is tracking on schedule and on budget. |
| Nanticoke Solar Facility | 2 | 3 | 107 | 2019 | Significant contracts for equipment and engineering construction services have been executed, with site preparation work to commence in March 2018. |
| Deep Geologic Repository (DGR) for L&ILW | 9 [2] | 204 [2] | | | On August 21, 2017, the federal Minister of Environment and Climate Change requested further information related to the project's environmental assessment (EA). OPG is working on a response to this information request. |

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the Nuclear Liabilities.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. The approved budget for the four-unit refurbishment is $12.8 billion, which includes the costs of the pre-requisite projects in support of the execution phase of the refurbishment. The first refurbished unit is scheduled to be returned to service in the first quarter of 2020 and the last unit is scheduled to be completed by 2026.

The Darlington Refurbishment project is a multi-phase program comprising the following five major sub-projects:

- Retube and Feeder Replacement, which includes the removal and replacement of feeder tubes and fuel channel assemblies in each reactor
- Turbines and Generators, which consists of inspections and repairs of turbine generator sets and the replacement of analog control systems with digital control systems
- De-fuelling and Fuel Handling, which involves the de-fuelling of the reactors and the refurbishment of the fuel handling equipment
- Steam Generators, which includes mechanical cleaning, water lancing, and inspection and maintenance work on the generators
- Balance of Plant, which consists of work on smaller projects to replace or repair certain other station components.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016 as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor was completed in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies, followed by the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection and installation activities, and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. The removal of fuel channel assemblies commenced in October 2017. The removal of pressure tubes as part of the fuel channel assemblies was completed in March 2018, with the removal of calandria tubes currently in progress. The removal of all reactor components is expected to be completed in mid-2018. Key projects in the second major segment completed to date in 2018 include the primary side steam generator layup and installation of steam generator access ports to support future inspections. Other key project activities being executed during the second segment include the continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC-approved Integrated Implementation Plan for the station.

Most of the pre-requisite projects, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in-service. This includes the Third Emergency Power Generator and the Containment Filtered Venting System safety enhancement projects placed in-service in April 2017, and the Re-tube Waste Processing Building completed in November 2017. Completion of the HWSF has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction to complete the facility recommenced in the fourth quarter of 2017. The HWSF is expected to be completed by the second quarter of 2019 and is not on the critical path for the Darlington Refurbishment project, which continues to track on schedule. The cost of the HWSF will be accommodated within the overall Darlington Refurbishment budget of $12.8 billion. Taking

into account the execution performance of the Unit 2 refurbishment and the cost to complete the HWSF, the overall Darlington Refurbishment project continues to track to the $12.8 billion budget.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of December 31, 2017, $93 million has been invested in planning activities related to the Unit 3 refurbishment. These planning activities are being undertaken in accordance with the refurbishment project schedule. In February 2018, the Government of Ontario confirmed its commitment to proceed with the refurbishment of Unit 3.

Peter Sutherland Sr. Hydroelectric GS

In March 2017, the project to construct the 28 MW two-unit Peter Sutherland Sr. hydroelectric GS successfully completed final testing and commissioning of the turbine and generator units, and both units were declared substantially completed. On March 31, 2017, the project received a permit from the MOECC to take water for operations to allow the station to operate commercially. This in-service date was well ahead of the originally planned schedule of the first half of 2018. The project's schedule had been accelerated to take advantage of favourable weather conditions. The project is expected to close below the approved budget of $300 million. Project close-out activities are in progress. OPG began to receive contracted revenue for the project following the IESO's confirmation of the station's commercial operations as of March 31, 2017, under a hydroelectric ESA. The Peter Sutherland Sr. hydroelectric GS is included in the Contracted Generation Portfolio segment.

The station was constructed through PSS, a partnership between OPG and CRP, a wholly owned subsidiary of the Taykwa Tagamou Nation. In April 2017, the CRP exercised its right under the partnership agreement to increase its interest in PSS to 33 percent.

Sir Adam Beck Pump GS Reservoir Refurbishment

The Sir Adam Beck Pump GS refurbishment construction began in April 2016 and the 300-hectare reservoir was returned to service in February 2017 upon completion of the reservoir commissioning program. The Sir Adam Beck Pump GS facility allows OPG to pump and store water diverted from the Sir Adam Beck generating complex during periods of low electricity demand, to be used to generate up to 600 MW of electricity during subsequent periods of high electricity demand. The work on the project included installation of a new partial liner and construction of a grout curtain in the bedrock foundation of the reservoir dyke. The refurbishment is expected to add approximately 50 more years to the reservoir's life. The project was completed ahead of the originally planned in-service date of April 2017 and below the approved budget of $58 million. The Sir Adam Beck Pump GS is included in the Regulated – Hydroelectric segment.

Ranney Falls Hydroelectric GS

In 2017, OPG began construction work on a 10 MW single-unit powerhouse on the existing Ranney Falls GS site. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure has been demolished and the new concrete structure has been completed. Excavation has been completed and construction continues in the expanded forebay, powerhouse and spillway area. The new forebay concrete wall has been completed, and concrete placement of the new powerhouse and the spillway integrated structure is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget. The Ranney Falls GS is included in the Regulated – Hydroelectric segment.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, will commence with site preparation work in March 2018.

During 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction. Significant contracts for equipment and engineering construction services were executed in the first quarter of 2018. The facility is expected to be completed in the first quarter of 2019, with a budget of $107 million.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW DGR on lands adjacent to the WWMF in Kincardine, Ontario.

Before the CNSC can make licensing decisions for the proposal, an EA must be conducted. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and Canadian Environmental Assessment Agency (CEAA)-appointed Joint Review Panel (JRP) to meet the requirements of the *Canadian Environmental Assessment Act* as well as the project specific Environmental Impact Statement Guidelines. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the EA process and advised that a draft report and updated terms and conditions would be prepared for public review.

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nation's (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land, taking into account the results of the SON Community Process. OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the information request.

The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

## Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future expansion. Inherent in this priority are four objectives:

- Increasing revenue, reducing costs and achieving appropriate return
- Ensuring availability of cost effective funding for operational needs, generation development projects and other business opportunities, and long-term obligations
- Pursuing opportunities to expand the existing core business and capitalize on new growth paths
- Managing risks, which is discussed in the section, *Risk Management*.

Increasing Revenue, Reducing Costs and Achieving Appropriate Return

In line with its commercial mandate, OPG is focused on increasing revenue and net income and achieving an appropriate rate of return on the Shareholder's investment, while taking into account the impact on Ontario electricity customers by seeking further efficiencies in the Company's cost structure.

For the regulated operations, achievement of the above objectives is largely dependent on outcomes of applications for regulated prices to the OEB and growth of the asset base earning a return as part of the regulated prices.

OPG has been focused on demonstrating in its applications for regulated prices that the costs required to operate and invest in the Company's regulated assets are reasonable and being prudently incurred, and should be fully recovered, and that the Shareholder's investment in these assets should earn an appropriate rate of return. While the OEB's December 2017 decision set allowed costs for determining the new regulated prices below the forecasted levels requested by OPG in its application, the decision will result in a substantial increase in revenue and net income compared to existing regulated prices. The previously approved nuclear base regulated prices were set in 2014 to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a Darlington refurbishment outage.

The OEB's decision to reduce recovery of OPG's forecasted cost levels, including through the use of stretch factors under incentive ratemaking, will negatively impact OPG's ability to earn an appropriate return on the Shareholder's investment in the regulated assets. To improve the financial strength of the regulated operations, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and pursue further efficiency improvements in the Company's cost structure and operating model. OPG's cost reduction and productivity improvement strategies are discussed further in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Improving Efficiency and Reducing Costs*.

OPG continues to invest in the regulated asset base, with the Darlington Refurbishment project being the single largest such capital investment. In its December 2017 decision, the OEB has allowed inclusion of a total of $5.5 billion in Darlington Refurbishment in-service capital additions by 2021 in the new regulated prices, excluding the HWSF. Once in service, these assets will attract the OEB-prescribed return on equity of approximately 8.8 percent as part of the regulated prices for the 2017-2021 period, based on the approved deemed capital structure of 45 percent equity and 55 percent debt. The average OEB-approved cost of deemed debt for the 2017-2021 period is approximately 4.6 percent. OPG also continues to pursue an extensive capital program across its regulated hydroelectric operations that includes expansion, redevelopment and life extension of the generating facilities, where economic. These renewable assets have long service lives and, with either maintenance efforts or rebuilding, will continue to supply electricity for the foreseeable future. The OEB's December 2017 decision on OPG's application for new regulated prices is discussed further in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

For generation assets that do not form part of the rate regulated assets, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term ESAs with the IESO or other long-term contracts. This includes the Peter Sutherland Sr. GS, which was placed in service and began receiving contracted revenue under a hydroelectric ESA as of March 31, 2017. The Peter Sutherland Sr. GS ESA expires in 2067.

OPG's capital structure currently reflects lower levels of debt than the deemed capital structure maintained by the OEB's December 2017 decision on new regulated prices. OPG continues to evaluate strategies to enhance Shareholder returns by optimizing the Company's capital structure through better alignment with the deemed capital structure, taking into account the overall financial strength of the Company and the potential impact on the Company's investment grade credit rating.

Ensuring Availability of Cost Effective Funding

OPG actively monitors its funding requirements and forecasts availability of funds to ensure that it can meet the Company's operational needs, project commitments and long-term obligations. OPG utilizes multiple sources of funds, including funds generated from operations, commercial paper, securitization of assets, letters of credit, credit facilities, long-term corporate debt sourced from the Ontario Electricity Financial Corporation (OEFC) and public debt offerings, credit facilities with the OEFC, private placement project financing, and equity issuances. The Company's financing strategy leverages the strength of its balance sheet to obtain cost effective long-term corporate debt. OPG also accesses the capital markets for private placement project financing, secured by the assets of the project, where

the characteristics of the project support such financing. Maintaining an investment grade credit rating is critical to OPG's ability to access cost effective financing.

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

The Company continues to evaluate arrangements that would appropriately support its financing needs, capital expenditure programs and purchases of subordinated debt issued by the Fair Hydro Trust. OPG's liquidity and capital resources are discussed in the section, *Liquidity and Capital Resources*.

Building Our Business

Through pursuit of commercial-based opportunities to expand its business, OPG strives to be a leader in the North American transition toward a low carbon future while maintaining and expanding the Company's scale and energy industry leadership. This strategy considers the Company's financial position and anticipated future changes in the generating fleet, including the eventual end of Pickering commercial operation. The strategy is also informed by industry, technological, environmental, social, and economic external factors. Opportunities are evaluated using financial and risk-based analyses as well as strategic considerations.

Currently, OPG's strategy primarily focuses on the renewal and expansion of the Company's portfolio of generating assets in Ontario, including the redevelopment and expansion of existing sites and potential new developments. The strategy leverages OPG's operating and project development expertise as well as the Company's existing diverse physical asset base. Acquisition opportunities are considered as they arise, taking into account operating synergies, strategic benefits, financial returns and risk profile. OPG's current major generation development projects and asset life extension initiatives are discussed in the section, *Core Business, Strategy, and Outlook* under the headings, *Operational Excellence* and *Project Excellence*.

OPG also actively seeks to expand beyond its core generation business through investments in innovation and emergent low-carbon technologies, including selective solar generation, nuclear innovation, energy storage, distributed generation, electric vehicle infrastructure and other development. Additionally, OPG continues to consider potential paths to extend its business through broader electricity sector opportunities, within and outside Ontario. Business expansion opportunities may be pursued in partnership with other commercial entities where appropriate synergies exist and are aligned with OPG's business objectives.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations. OPG works to maintain public trust with stakeholders by engaging site communities, sharing information, and being transparent about performance. In addition, OPG's operations are subject to extensive regulatory oversight, with public participation, by the CNSC, the OEB, and other bodies. OPG's commitment to safety is discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Workplace and Public Safety*.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

OPG's commitment in this area includes pursuing generation-related development partnerships on the basis of long-term commercial arrangements, such as the construction of the Peter Sutherland Sr. GS in partnership with Taykwa Tagamou Nation and the development of the Nanticoke solar facility in partnership with the Six Nations of the Grand River. During 2017, OPG also continued to engage with Indigenous communities regarding the Company's nuclear waste management operations, through regularly scheduled meetings and ongoing dialogue in connection with OPG's proposed L&ILW DGR and the re-licensing of the PWMF and the WWMF, as well as regarding the Pickering GS re-licensing. Engagement was also conducted with First Nations in southwestern Ontario regarding the demolition of the Lambton and Nanticoke generating stations and with the Mississaugas of New Credit regarding the sale of the former Lakeview GS site.

OPG is committed to improving Indigenous access to procurement and employment opportunities, including increasing the profile of the nuclear generation industry in Indigenous communities. In 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will: identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has been engaging with Indigenous businesses and communities as well as its suppliers to promote the IBE Initiative, including the Mohawk Council of Akwesasne and the Williams Treaties First Nations located proximate to the Pickering and Darlington nuclear generating stations.

OPG has been actively developing recruitment plans targeting Indigenous peoples. As part of this initiative, during the fourth quarter of 2017, OPG participated in several Indigenous-specific career fairs, hosted a Day in the Trades event for Indigenous students and job seekers as part of an open house at the Darlington Energy Centre, and approved plans aimed at increasing the number of Indigenous apprentices as part of the nuclear operations' recruitment program.

OPG also contributes to the well-being of its host communities through the Company's Corporate Citizenship Program (CCP), which supports charitable and non-profit grassroots initiatives in the areas of environment, education, and community involvement, including support for Indigenous initiatives. In 2017, OPG's CCP provided support to over 800 initiatives, of which 84 were Indigenous.

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector. Ontario's climate change plan aims for electric and hydrogen passenger vehicles to represent five percent of new vehicle sales in the province by 2020.

As part of its commitment to help de-carbonize Ontario's transportation sector, OPG is a founding sponsor of Plug'n Drive, a non-profit organization working to accelerate the adoption of electric vehicles and to maximize their environmental and economic benefits. In May 2017, Plug'n Drive announced the opening of the world's first experiential learning facility dedicated to electric vehicle education and awareness, with OPG sponsoring the Centre's training facility.

Further details regarding OPG's commitment to sustainable development, including information regarding the Company's environmental and social performance and initiatives, are provided in OPG's 2016 Sustainability Report available on the Company's website at www.opg.com.

## Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. Subject to the OEB's issuance of the final payment amounts order expected in the first half of 2018, the OEB's December 2017 decision on new regulated prices provides substantial price certainty for the regulated business for the 2017 to 2021 period. During this period, OPG will continue to focus on optimizing operational performance and outage plans across the generating fleet and on pursuing further efficiency improvements in the Company's cost structure and operating model.

The OEB's decision established June 1, 2017 as the effective date of the new regulated prices, which negatively affected OPG's net income and ROE Excluding AOCI in 2017 relative to OPG's requested effective date of January 1, 2017. The full-year effect of new regulated prices in 2018 is expected to contribute to an improvement in net income and ROE Excluding AOCI over the 2017 results.

Subject to the OEB's final determination on nuclear rate smoothing as part of the payment amounts order process, OPG expects an improvement in cash flow from operating activities in 2018, compared to 2017. This will reflect OPG beginning to collect revenue from the IESO based on new regulated prices once the final payment amounts order is approved. Additionally, the Fair Hydro Trust segment will begin to contribute positive cash flow from operating activities in 2018. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements, including purchases of subordinated debt issued by the Fair Hydro Trust to fund a portion of the Trust's acquisition of Investment Interest from the IESO.

Several OEB-authorized regulatory variance and deferral accounts contribute to reducing the relative variability of the Company's net income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO or other long-term contracts. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operating activities going forward.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC and Nuclear TGC measures for the duration of the refurbishment project. Lower hydroelectric generation due to outages related to various refurbishment and operational projects may negatively impact Enterprise TGC and Hydroelectric TGC for the duration of these projects. Variability in sustaining capital investment expenditures and nuclear outage profile may also impact TGC measures in future periods.

OPG's total forecast capital expenditures for the 2018 year are approximately $2.1 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the Ranney Falls GS redevelopment and construction of the Nanticoke solar facility, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel

Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is reduced by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and when the funds are in a fully funded or overfunded position, as discussed further in the section, *Risk Management* under the heading, *Nuclear Liabilities and Nuclear Segregated Funds*.

As at December 31, 2017, the Decommissioning Segregated Fund was overfunded by approximately 27 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

OPG's results include the earnings from the Fair Hydro Trust segment, primarily related to interest income from the Trust. Management expects that these earnings will increase in 2018. OPG's involvement as the Financial Services Manager under the Fair Hydro Act is expected to put downward pressure on ROE Excluding AOCI as a result of increases in shareholder's equity through future issuances of Class A shares to partially fund OPG's purchases of the Trust's subordinated debt, partially offset by the impact of incremental earnings from the Trust.

## KEY OPERATING AND FINANCIAL PERFORMANCE INDICATORS

OPG evaluates the performance of its generating stations using a number of key indicators. Key operating performance indicators aligned with corporate strategic imperatives are measures of production reliability, cost effectiveness, environmental performance, and safety performance. Certain of the measures used vary depending on the generating technology.

Enterprise TGC, Nuclear TGC, Hydroelectric TGC, ROE Excluding AOCI, and FFO Adjusted Interest Coverage ratio discussed below are not measurements in accordance with US GAAP. They should not be considered as alternative measures to net income or any other measure of performance under US GAAP. However, OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of Enterprise TGC per MWh, Nuclear TGC per MWh, Hydroelectric TGC per MWh, ROE Excluding AOCI, and FFO Adjusted Interest Coverage are found in the section, *Supplementary Non-GAAP Financial Measures*.

### Enterprise Total Generating Cost per Megawatt-Hour

Enterprise TGC per MWh is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

### Nuclear Total Generating Cost per Megawatt-Hour

Nuclear TGC per MWh is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to OPG's nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project) incurred during the period, divided by nuclear electricity generation for the period.

### Hydroelectric Total Generating Cost per Megawatt-Hour

Hydroelectric TGC per MWh is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segments (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

### Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities that are not designed for fluctuating production levels to meet peaking demand. The nuclear Unit Capability Factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. By industry definition, capability factors exclude production losses beyond plant management's control, such as grid-related unavailability. The nuclear Unit Capability Factor also excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS is excluded from the measure effective October 15, 2016, when the unit was taken offline as part of the Darlington Refurbishment project.

### Hydroelectric Availability

OPG's hydroelectric stations operate as baseload, intermediate, or peaking stations. Hydroelectric Availability represents the percentage of time the generating unit is capable of providing service, whether or not it is actually generating electricity, compared to the total time for the respective period.

### Thermal Equivalent Forced Outage Rate

Equivalent Forced Outage Rate (EFOR) is an index of the reliability of a generating unit at OPG's thermal stations. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

### Return on Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's financial performance consistent with its objective to deliver value to the Shareholder. ROE Excluding AOCI is defined as net income attributable to the Shareholder for the period divided by average equity attributable to the Shareholder excluding AOCI for that period, and is measured over a period of 12 months.

### Funds from Operations Adjusted Interest Coverage

The FFO Adjusted Interest Coverage ratio is an indicator of OPG's ability to meet interest obligations from operating cash flow and is consistent with the Company's objective of ensuring availability of cost effective funding. The FFO Adjusted Interest Coverage ratio is defined as FFO before interest divided by adjusted interest expense, and is measured over a period of 12 months.

### Other Key Indicators

In addition to production reliability, cost effectiveness, and financial performance indicators, OPG has identified certain environmental and safety performance measures. These measures are discussed in the section, *Core Business, Strategy, and Outlook*.

## BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust.

### Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from existing isotope sales contracts and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support.

### Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered rate regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

### Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 hydroelectric generation stations located across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

### Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA with the IESO or other long-term contracts.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations. Brighton Beach operates under an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc., and the PEC station is operated under the terms of an Accelerated Clean Energy Supply contract with the IESO. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are reported in this segment.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

### Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities.

As part of trading activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets, with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

### Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It reports OPG's income related to its role as the Financial Services Manager under the Fair Hydro Act and holder of the Trust's subordinated debt, and includes the financial results of the Trust. Segment earnings include interest income from the Trust, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund its purchase of the Trust's subordinated debt, incurred third-

party costs, and other costs incurred related to the management and administration of the Trust. OPG's fees for its services to the Trust, as the Financial Services Manager, are subject to an annual review by the OEB.

## DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

### Regulated – Nuclear Generation Segment

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Revenue | **3,095** | 3,481 |
| Fuel expense | **284** | 315 |
| Gross margin | **2,811** | 3,166 |
| Operations, maintenance and administration | **2,293** | 2,210 |
| Depreciation and amortization | **431** | 925 |
| Property taxes | **26** | 26 |
| Income before other losses, interest, and income taxes | **61** | 5 |
| Other losses | **4** | 1 |
| Income before interest and income taxes | **57** | 4 |

Income before interest and income taxes from the segment increased by $53 million in 2017, compared to 2016. Segment earnings were affected by the OEB's decision on new regulated prices issued in December 2017 with a retrospective effective date of June 1, 2017. In the fourth quarter of 2017, the segment recorded net revenue of approximately $465 million in relation to the June 1, 2017 to December 31, 2017 period resulting from the OEB's decision, as an increase in net regulatory assets. This revenue increase was based on new regulated prices proposed in OPG's January 2018 draft payment amounts order submission to the OEB based on the findings in the decision and is net of a regulatory liability recognized in relation to OPG's nuclear rate smoothing proposal in that submission.

Segment earnings were unfavourably affected by a reduction in electricity generation of 4.9 TWh in 2017, compared to 2016. This reduced revenue by approximately $285 million, partially offset by a decrease in fuel expense. The lower electricity generation was primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, partially offset by the higher electricity generation from the Pickering GS. The income impact of OEB-approved regulatory accounts also contributed to the decrease in income for the year.

The increase in OM&A expenses of $83 million in 2017, compared to 2016, reflected planned expenditures related to the major maintenance activities occurring at the nuclear stations and higher nuclear project expenses. Depreciation and amortization expenses, excluding amortization expense related to regulatory account balances, increased by $22 million, primarily due to new assets in service in 2017.

The expiry of a nuclear rate rider for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016 contributed to the decrease in segment revenue in 2017, compared to 2016, but was largely offset by a decrease in amortization expense related to these balances.

The Unit Capability Factors for the Darlington GS and Pickering GS for 2017 and 2016 were as follows:

| | **2017** | **2016** |
|---|---|---|
| Unit Capability Factor *(%)* [1] | | |
| Darlington GS | **85.2** | 89.5 |
| Pickering GS | **80.0** | 75.2 |

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The lower Unit Capability Factor at the Darlington GS in 2017, compared to 2016, reflected the higher number of planned outage days in 2017, largely driven by constraints related to the transition of the station's operating units toward refurbishment.

The increase in the Unit Capability Factor at the Pickering GS in 2017, compared to 2016, was primarily due to outage cycle optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

The definition of the nuclear Unit Capability Factor is found in the section, *Key Operating and Financial Performance Indicators.*

**Regulated – Nuclear Waste Management Segment**

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Revenue | **121** | 138 |
| Operations, maintenance and administration | **129** | 146 |
| Accretion on nuclear fixed asset removal and nuclear waste management liabilities | **943** | 912 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(801)** | (746) |
| Loss before interest and income taxes | **(150)** | (174) |

Earnings from the segment improved by $24 million in 2017 compared to 2016. The improvement was primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities.

The year-over-year increase in earnings from the Nuclear Segregated Funds was primarily due to a reduction in the earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets reported on the consolidated balance sheet to the underlying funding liabilities per the 2017 ONFA Reference Plan. The 2017 ONFA Reference Plan resulted in a reduction in the funding liabilities. As both the Decommissioning Segregated Fund and the Used Fuel Fund have been in an overfunded position since the beginning of 2017, the earnings on the funds recognized in net income during the year reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and the rate of return guaranteed by the Province for a portion of the Used Fuel Segregated Fund. Further details on the accounting for the Nuclear Segregated Funds can be found in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

As of December 31, 2015, OPG recorded an increase of approximately $2,330 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The increase was related to revised accounting assumptions for the estimated useful lives of OPG's nuclear generating stations, including an extension in the end-of-life dates for the Bruce nuclear generating stations in line with the updated refurbishment agreement between the IESO and Bruce Power. As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs to reflect an updated estimate of OPG's obligations for nuclear waste management and nuclear facilities decommissioning determined as part of the 2017 ONFA Reference Plan update process.

The above revisions to the Nuclear Liabilities resulted in changes to accretion expense over 2016 and 2017. Prior to June 1, 2017, the income impact of these changes was largely offset by the impact of OEB-authorized regulatory accounts recorded against accretion expense. For the June 1, 2017 to December 31, 2017 period, the income impact of these changes was largely offset by the retrospective revenue impact of the OEB's decision on new regulated prices, which incorporated the above changes in the Nuclear Liabilities and was recorded in the Regulated – Nuclear Generation segment. Therefore, while the overall impact of the above revisions in Nuclear Liabilities on

OPG's income was largely offset in both 2016 and 2017, there was a year-over-year increase in accretion expense reported in 2017, compared to 2016.

**Regulated – Hydroelectric Segment**

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Revenue [1] | **1,436** | 1,527 |
| Fuel expense | **351** | 353 |
| Gross margin | **1,085** | 1,174 |
| Operations, maintenance and administration | **330** | 325 |
| Depreciation and amortization | **139** | 225 |
| Property tax | **1** | 1 |
| Income before other gains, interest and income taxes | **615** | 623 |
| Other losses (gains) | **1** | (19) |
| Income before interest and income taxes | **614** | 642 |

[1] During 2017 and 2016, the Regulated – Hydroelectric segment revenue included incentive payments of $12 million and $14 million, respectively, related to the OEB-approved hydroelectric incentive mechanism. The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The decrease in segment income before interest and income taxes of $28 million in 2017, compared to 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision reversing a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved regulatory accounts and higher OM&A expenses also contributed to the decrease in income for the year. The higher OM&A expenses were primarily related to overhaul work and civil repairs completed during the year.

These factors were partially offset by the recognition of revenue of approximately $15 million in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on new regulated prices effective June 1, 2017, recorded as an increase to regulatory assets.

The decrease in revenue from the segment in 2017, compared to 2016, was largely due to the expiry of an OEB-authorized hydroelectric rate rider on December 31, 2016. As the rate rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by lower amortization expense related to these balances.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

| | **2017** | **2016** |
|---|---|---|
| Hydroelectric Availability *(%)* | **88.0** | 89.0 |

The Hydroelectric Availability decreased during 2017, compared to 2016, primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara regions' hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS due to a higher number of planned outage days in 2016 reflecting the refurbishment of the station's reservoir.

The definition of Hydroelectric Availability is found in the section, *Key Operating and Financial Performance Indicators*.

## Contracted Generation Portfolio Segment

| *(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| Revenue | **579** | 573 |
| Fuel expense | **53** | 58 |
| Gross margin | **526** | 515 |
| Operations, maintenance and administration | **169** | 178 |
| Depreciation and amortization | **79** | 75 |
| Accretion on fixed asset removal liabilities | **9** | 9 |
| Property taxes | **7** | 7 |
| Income from investments subject to significant influence | **(38)** | (37) |
| Income before other losses, interest, and income taxes | **300** | 283 |
| Other losses | **-** | 1 |
| Income before interest and income taxes | **300** | 282 |

Income before interest and income taxes from the segment increased by $18 million during 2017, compared to 2016. The increase in earnings primarily resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenues from the Lower Mattagami River hydroelectric generating stations and the Atikokan GS. The lower OM&A expenses were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017. This change in approach is discussed further in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

The Hydroelectric Availability and the Thermal EFOR for the Contracted Generation Portfolio segment were as follows:

| | 2017 | 2016 |
|---|---|---|
| Hydroelectric Availability *(%)* | **74.6** | 77.3 |
| Thermal EFOR *(%)* | **2.4** | 1.6 |

Lower Hydroelectric Availability during 2017, compared to 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR in 2017, compared to 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator-related outage in 2017.

The definitions of Hydroelectric Availability and Thermal EFOR are found in the section, *Key Operating and Financial Performance Indicators*.

### Services, Trading, and Other Non-Generation Segment

| *(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| Revenue | **43** | 68 |
| Fuel expense | **1** | 1 |
| Gross margin | **42** | 67 |
| Operations, maintenance and administration | **18** | 22 |
| Depreciation and amortization | **30** | 32 |
| Accretion on fixed asset removal liabilities | **8** | 8 |
| Property taxes | **6** | 12 |
| Restructuring | **-** | 6 |
| Loss before other gain, interest, and income taxes | **(20)** | (13) |
| Other gains | **(384)** | - |
| Income (loss) before interest and income taxes | **364** | (13) |

Segment earnings improved by $377 million in 2017 compared to 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017 in the amount of $283 million, which is net of tax effects of $95 million. The increase in earnings was partially offset by a decrease in rental revenue due to the sale of the head office premises.

The year-over-year decrease in OM&A expenses in 2017 reflected higher expenses incurred in 2016 prior to the decision taken in the fourth quarter of 2016 to proceed with the decommissioning of the Lambton GS, largely offset by a higher amount of previously incurred project expenditures written off in 2017.

During the fourth quarter of 2017, OPG recorded $12 million in Other gains related to the revaluation of the ARO for the Lambton and Nanticoke generating stations in line with the current decommissioning plans and cost estimates. The revaluation of the ARO is discussed further in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. During each of 2017 and 2016, OPG recorded a charge against earnings to adjust the scrap value estimate for the Lambton GS, as a reduction to Other gains.

### Fair Hydro Trust Segment

| *(millions of dollars)* | 2017 |
|---|---|
| Operations, maintenance and administration | **1** |
| Earnings from Fair Hydro Trust | **(1)** |
| Income before interest and income taxes | **-** |

The Fair Hydro Trust was established on December 20, 2017. Earnings from Fair Hydro Trust were $1 million in 2017, primarily due to net interest income for the 11-day period following the acquisition of the first tranche of Investment Interest from the IESO on December 21, 2017. The earnings were offset by OM&A expenses for labour costs relating to OPG's employees that were not exclusively dedicated to the segment but who provided services to set up the Trust during the year. Pursuant to the general regulation of the Fair Hydro Act, such labour costs are not recoverable as part of OPG's fees for 2017. Refer to the section, *Highlights* under the heading, *Recent Developments – Ontario's Fair Hydro Plan* and the section, *Business Segments* under the heading, *Fair Hydro Trust Segment* for further details on the Fair Hydro Trust.

## LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the OEFC, long-term corporate debt, including public debt offerings and notes payable to the OEFC, private placement project financing, and equity issuances. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not eligible for reimbursement from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund a portion of OPG's purchases of subordinated debt issued by the Fair Hydro Trust.

Changes in cash and cash equivalents for 2017 and 2016 were as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Cash and cash equivalents, beginning of period | **186** | 464 |
| Cash flow provided by operating activities | **944** | 1,817 |
| Cash flow used in investing activities | **(2,478)** | (1,919) |
| Cash flow provided by (used in) financing activities | **1,582** | (176) |
| Net increase (decrease) in cash and cash equivalents | **48** | (278) |
| Cash and cash equivalents, end of period | **234** | 186 |

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

### Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities in 2017 increased by $559 million compared to 2016. The increase in net cash flow used in investing activities was primarily due to the Trust's acquisition of the first tranche of Investment Interest from the IESO of approximately $1.18 billion in December 2017 and higher expenditures on the Darlington Refurbishment project in 2017.

The increase in net cash flow used in investing activities was partially offset by the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in 2017 and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in 2016. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the current collective agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society).

### Financing Activities

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018. As at December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

During 2017, OPG issued a total of $800 million senior note payable to the OEFC maturing in 2047. The effective and coupon interest rates on these notes ranged from 3.65 percent to 4.12 percent, as detailed in Note 6 of OPG's 2017 audited consolidated financial statements.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 21, 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this credit facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The Province provided an additional $519 million for this acquisition through an equity injection in OPG in exchange for approximately 12.2 million non-voting Class A shares as discussed in further detail in Note 14 of OPG's 2017 audited consolidated financial statements.

In February 2018, the Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017. In March 2018, the Trust is expected to acquire another tranche of Investment Interest from the IESO, with 51 percent of the funding being sourced from the revolving warehouse facility, 44 percent through an equity injection from the Province, and five percent from OPG.

As at December 31, 2017, OPG's long-term debt outstanding was $5,735 million, including $398 million due within one year and excluding Fair Hydro Trust's senior debt reported on OPG's consolidated balance sheets. The Fair Hydro Trust's senior debt outstanding was $601 million as at December 31, 2017.

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at December 31, 2017.

There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017.

As at December 31, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million of commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the $300 million tranche of LME's credit facility.

As at December 31, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $468 million of short-term, uncommitted credit facilities which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at December 31, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

## Contractual Obligations

OPG's contractual obligations as at December 31, 2017 are as follows:

| *(millions of dollars)* | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Fuel supply agreements | 158 | 125 | 115 | 88 | 67 | 67 | 620 |
| Contributions to the OPG registered pension plan [1] | 215 | 219 | - | - | - | - | 434 |
| OPG long-term debt repayment | 398 | 368 | 663 | 413 | 172 | 3,721 | 5,735 |
| Interest on OPG long-term debt | 244 | 226 | 204 | 175 | 161 | 3,006 | 4,016 |
| Fair Hydro Trust senior debt repayment [2] | - | 601 | - | - | - | - | 601 |
| Interest on Fair Hydro Trust senior debt | 15 | 15 | - | - | - | - | 30 |
| Commitments related to Darlington Refurbishment project [3] | 457 | - | - | - | - | - | 457 |
| Commitments related to Ranney Falls GS project | 5 | - | - | - | - | - | 5 |
| Operating licences | 40 | 41 | 24 | 28 | 28 | 87 | 248 |
| Operating lease obligations | 28 | 24 | 24 | 22 | 22 | 79 | 199 |
| Unconditional purchase obligations | 62 | 59 | 56 | 5 | - | - | 182 |
| Accounts payable and accrued charges | 957 | 8 | - | - | - | 16 | 981 |
| Other | 47 | 28 | 2 | 1 | 1 | 64 | 143 |
| Total | 2,626 | 1,714 | 1,088 | 732 | 451 | 7,040 | 13,651 |

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Other Commitments

*Collective Agreements*

As of December 31, 2017, OPG had approximately 9,200 regular employees. Most of OPG's regular employees are represented by two unions:

- The PWU – This union represents approximately 4,850 OPG employees or approximately 53 percent of OPG's regular workforce as at December 31, 2017. Union membership includes operators, technicians, skilled trades, clerical, and security personnel. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. Negotiations for a new labour agreement with the PWU are underway.
- The Society – This union represents approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce as at December 31, 2017. Union membership includes supervisors, professional engineers, scientists, and other professionals. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

In addition to the regular workforce, construction work is performed through 19 craft unions with established bargaining rights at OPG facilities. These bargaining rights are established either through the Electrical Power Systems Construction Association (EPSCA) or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA. All of these collective agreements currently have multi-year terms, expiring on April 30, 2020.

**BALANCE SHEET HIGHLIGHTS**

The following section provides other highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Property, plant and equipment – net** | **21,322** | 19,998 |
| The increase was primarily due to capital expenditures on the Darlington Refurbishment and other projects, partially offset by depreciation expense. | | |
| **Nuclear fixed asset removal and nuclear waste management funds** *(current and non-current portions)* | **16,724** | 15,984 |
| The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities. | | |
| **Regulatory assets and liabilities – net** *(current and non-current portions)* | **6,637** | 5,545 |
| The increase was primarily due to the recognition of net revenue related to the June 1, 2017 to December 31, 2017 period resulting from the OEB's December 2017 decision on new regulated prices and the re-measurement of the pension and OPEB liabilities at the end of 2017. | | |
| **Long-term debt** *(current and non-current portions)* | **6,319** | 5,520 |
| The increase was primarily due to the issuance of senior notes payable by the Fair Hydro Trust of $601 million to finance the acquisition of Investment Interest from the IESO, issuance of senior notes payable to the OEFC totalling $800 million, and issuance of senior notes of $500 million under the Medium Term Note Program. The increase was offset by debt repayment totalling $1,100 million. | | |
| **Fixed asset removal and nuclear waste management liabilities** | **20,421** | 19,484 |
| The increase was primarily a result of accretion expense representing the increase in the present value liabilities due to the passage of time, and an increase in the estimate for the nuclear asset retirement obligation of $188 million recorded in 2017, which is discussed in the section, *Critical Accounting Policies and* Estimates under the heading, *Asset Retirement Obligation*. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities. | | |
| **Pension liabilities** | **3,423** | 3,012 |
| The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on pension plan assets over interest costs on the liabilities during 2017. | | |
| **Other post-employment benefit liabilities** | **3,092** | 2,897 |
| The increase was primarily due to the re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation. | | |

### Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements to provide financial or performance assurance to third parties. Such agreements include guarantees, standby Letters of Credit and surety bonds. For more details on guarantees issued by the company, refer to Note 16 of OPG's 2017 audited consolidated financial statements.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of major recent accounting pronouncements, are outlined in Note 3 of OPG's 2017 audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's US GAAP consolidated financial statements are highlighted below.

### Exemptive Relief for Reporting under US GAAP

As required by *Ontario Regulation 395/11,* as amended, under the FAA, OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the OSC from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements with the OSC based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a U.S. Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board (IASB) for the mandatory application of a standard within IFRS specific to entities with rate-regulated activities.

The Company is in the process of applying for a further extension of this exemptive relief beyond January 1, 2019.

As a result of adopting US GAAP in 2011 as required by the FAA regulation, OPG's earlier plan to convert to IFRS, effective January 1, 2012, was discontinued. OPG had substantively completed its IFRS conversion project when it suspended the project. If a future transition to IFRS for the purposes of OPG's consolidated financial statements is required, conversion work can be effectively restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project. OPG continues to monitor the IASB's current standard-setting project related to entities with rate-regulated activities and is evaluating alternatives with respect to the Company's future financial reporting.

## Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations. OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and regulatory liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* The measurement of these regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and regulatory liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

In addition to regulatory assets and regulatory liabilities for variance and deferral accounts, OPG recognizes regulatory assets and regulatory liabilities for unamortized amounts recorded in AOCI in respect of pension and OPEB obligations, deferred income taxes, and differences between interim regulated prices charged to customers during an interim rate period and final regulated prices authorized or to be authorized by the OEB for that period, to reflect the expected recovery or repayment of these amounts through future regulated prices to be charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations and deferred income taxes that are attributed to rate regulated business segments, and assumptions made with respect to final regulated prices to be authorized by the OEB for the interim rate period.

The regulatory asset recognized by the Company for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's actual cash expenditures for these

plans is captured in the OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration by the OEB.

In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 2017 decision on OPG's new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, until such time as the OEB decides on the approval and implementation of resumption of the accrual basis of recovery for OPG. The future recovery of amounts recorded in the account will be subject to this approval. Further details on the OEB's 2017 report can be found in the section, *Highlights* under the heading, *Recent Developments – OEB's Decision on OPG's Application for New Regulated Prices*.

It is the Company's position that the OEB's November 2014 and December 2017 decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices, or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Similarly, the Company continues to believe that there is sufficient likelihood that amounts recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account will be recovered, and consistent with the expectations set out in the OEB's December 2017 decision, plans to file an application with the OEB in 2018 requesting recovery of the account balance and approval to resume the accrual basis accounting as the recovery methodology in future applications for base regulated prices. Therefore, the Company continues to recognize regulatory assets for the above amounts.

### Useful Lives of Long-Lived Assets

The accounting estimates related to end-of-life assumptions for property, plant and equipment (PP&E) and intangible assets require significant management judgment, including consideration of various operating, technological and economic factors. OPG reviews the estimated useful lives for its PP&E and intangible assets, including end-of-life assumptions for major generating assets, on a regular basis. Major nuclear station components are depreciated over the lessor of the station life and the life of the components.

For nuclear generating stations operated by OPG, establishing station end-of-life assumptions primarily involves an assessment of operating lives of major life-limiting components such as fuel channel assemblies, taking into account expectations of future ability to economically operate and as appropriate refurbish the station for continued use. Expected operating lives of major life-limiting components are established through technical assessments of their fitness-for-service. Expectations of future ability to operate the station may be affected by operating licence requirements, ability to recovery capital, operating and decommissioning costs, and government policy, among other factors.

Although there is a link between the age of a hydroelectric facility and the capital investment required to maintain that facility, age does not generally establish an overall upper limit on the expected useful life of a hydroelectric generating station. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. An estimated useful life not exceeding 100 years is used by OPG to depreciate dams and other major hydroelectric station structures.

Station end-of-life assumptions for thermal generating stations are establishing based on operating life expectations of major station components and expectations of future ability to economically operate the station taking into consideration available revenue mechanisms.

## Financing Receivables

OPG's financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

## Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear facilities decommissioning and long-term nuclear waste management. The Decommissioning Segregated Fund was established to fund the future costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the stations are shut down. The Used Fuel Segregated Fund was established to fund the future costs of long-term nuclear used fuel management and certain costs of used fuel storage incurred after the stations are shut down. Costs for L&ILW management and used fuel storage incurred during station operation are not funded by the Nuclear Segregated Funds. They are funded through the Company's operating cash flow or other sources of liquidity.

Based on the current approved ONFA reference plan, starting in 2017, OPG is not currently required to make overall contributions to the Used Fuel Segregated Fund or the Decommissioning Segregated Fund. Prior to 2017, OPG made contributions to the Used Fuel Segregated Fund quarterly, including a one-time special payment in earlier years, as required by the ONFA. These contributions reflected ONFA requirements to fund the majority of the underlying used fuel liability by the end of the initial estimated useful lives of the nuclear stations assumed in the ONFA, resulting in significantly higher contributions to the Used Fuel Segregated Fund in the earlier years of OPG's existence. OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through the initial contribution made by the OEFC, an agency of the Province and, taking into account asset performance and changes in underlying funding obligations over time, at the time of every subsequent approved ONFA reference plan. Contributions to either or both funds may be required in the future should the funds be in an underfunded position when a new reference plan is prepared. Such may be the case as a result of variability in asset performance due to volatility inherent in financial markets and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province, changes in the Ontario CPI. Future contribution levels also are dependent on changes in baseline cost estimates and underpinning assumptions used to establish the funding obligations in subsequent ONFA reference plans.

Decommissioning Segregated Fund

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the fund asset recognized on the consolidated balance sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new or amended reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded.

The amount due to the Province in respect of the Decommissioning Segregated Fund could be reduced in subsequent periods in the event that the fund earns less than is target rate of return, a new ONFA reference plan is

approved with a higher underlying liability, or the amount of the underfunding in the Used Fuel Segregated Fund increases.

When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

Used Fuel Segregated Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined in the ONFA, for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund's assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount represents the amount OPG would pay to, or receive from, the Province if the committed return were to be settled as of the consolidated balance sheet date. Upon approval of a new or amended ONFA reference plan, the Province is obligated to make an additional contribution to the Used Fuel Segregated Fund in relation to the first 2.23 million used fuel bundles if the fund's assets earned a rate of return that is less than the guaranteed rate of return. If the return on the fund's assets exceeds the Province's guaranteed rate of return, the Province is entitled to withdraw any portion of the excess related to the first 2.23 million used fuel bundles, upon approval of a new or amended ONFA reference plan. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions attributed to the used fuel bundles in excess of the first 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the funding liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund. Accordingly, when the Used Fuel Segregated Fund is overfunded, OPG limits the fund earnings it recognizes in the consolidated financial statements by recording an amount due to the Province, such that the balance of the fund is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. In accordance with the ONFA, neither OPG nor the Province have a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund.

Provincial Guarantee

In accordance with the *Nuclear Safety and Control Act* (Canada), the CNSC requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear decommissioning obligations. The CNSC process requires the CNSC financial guarantee requirement to be updated once every five years and for OPG to provide an annual report to the CNSC on the assumptions, asset values, and resulting financial guarantee requirements. The CNSC financial guarantee requirement calculation takes into account nuclear waste expected to be generated to the end of each year.

In November 2017, the CNSC accepted OPG's proposed 2018-2022 CNSC financial guarantee requirement to be satisfied by the forecast fair market value of the Nuclear Segregated Funds without the requirement of a Provincial Guarantee for the 2018-2022 period. As provided for by the terms of the ONFA, the Province is committed to provide a Provincial Guarantee to the CNSC as required, on behalf of OPG, should there be a shortfall between the CNSC financial guarantee requirement and the fair market value of the Nuclear Segregated Funds during the 2018-2022 period, as it has done in the past. OPG pays the Province an annual guarantee fee equal to 0.5 percent of the outstanding amount, if any, of the Provincial Guarantee.

The value of the Provincial Guarantee in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2016 and 2017.

## Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions, as discussed below.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the Nuclear Waste Management Organization (NWMO), which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor) for each plan is amortized over the expected average remaining service life of the employees covered by the plan, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income (OCI), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as amortization components of pension and OPRB costs as described above.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

| *(millions of dollars)* | Registered Pension Plans 2017 | Registered Pension Plans 2016 | Supplementary Pension Plans 2017 | Supplementary Pension Plans 2016 | Other Post-Employment Benefits 2017 | Other Post-Employment Benefits 2016 |
|---|---|---|---|---|---|---|
| Net actuarial gain not yet subject to amortization due to use of market-related values | **(418)** | (570) | **-** | - | **-** | - |
| Net actuarial loss not subject to amortization due to use of the corridor | **1,735** | 1,619 | **36** | 34 | **299** | 267 |
| Net actuarial loss subject to amortization | **2,333** | 2,238 | **80** | 72 | **79** | 3 |
| Unamortized net actuarial loss | **3,650** | 3,287 | **116** | 106 | **378** | 270 |
| Unamortized past service costs | **-** | - | **-** | - | **4** | 5 |

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the reclassification of AOCI amounts into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost, and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The discount rate used to determine the projected pension and OPEB benefit obligations as at December 31, 2017 was approximately 3.6 percent. This represents a decrease compared to the discount rate of approximately 3.9 percent that was used to determine the obligations as at December 31, 2016.

Effective January 1, 2017, OPG changed the approach to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous approach used in 2016 and prior years, these components of pension and OPEB costs were calculated using the same single equivalent discount rate as reflected in the calculation of the benefit obligations. This change in the approach was accounted for prospectively, as a change in

estimate. The resulting reduction in 2017 pension and OPEB costs was approximately $135 million. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligations, as the change in the current service and interest cost components from the previous approach is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

The expected rate of return on plan assets is determined based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in the section, *Liquidity and Capital Resources* under the heading, *Contractual and Commercial Commitments*. As part of the valuation, the plan's demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries. Using these updated demographic assumptions and demographic data as at January 1, 2017 consistent with the new funding valuation for the registered pension plan, OPG conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017. The results of this valuation were reflected in the 2017 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2017.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB plans increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a re-measurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

| *(millions of dollars)* | Registered Pension Plans [1] | Supplementary Pension Plans [1] | Other Post-Employment Benefits [1] |
|---|---|---|---|
| Expected long-term rate of return | | | |
| 0.25% increase | (32) | n/a | n/a |
| 0.25% decrease | 32 | n/a | n/a |
| Discount rate | | | |
| 0.25% increase | (56) | (1) | (2) |
| 0.25% decrease | 59 | 1 | 13 |
| Inflation [2] | | | |
| 0.25% increase | 98 | 1 | - |
| 0.25% decrease | (91) | (1) | - |
| Salary increases | | | |
| 0.25% increase | 22 | 3 | - |
| 0.25% decrease | (20) | (2) | - |
| Health care cost trend rate | | | |
| 1% increase | n/a | n/a | 77 |
| 1% decrease | n/a | n/a | (29) |

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

[2] With a corresponding change in the salary increase assumption

## Asset Retirement Obligation

OPG recognizes ARO for fixed asset removal and nuclear waste management liabilities, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. Costs are expected to be incurred for activities such as preparation for safe storage and safe storage of nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel bundles and L&ILW material. The liabilities associated with the decommissioning of the nuclear generating stations and the long-term management of used nuclear fuel comprise the most significant amounts of the total obligation.

The nuclear decommissioning liability includes the estimated costs of closing the nuclear stations after the end of their service lives, which includes preparation and placement of the stations into a safe storage state followed by an assumed 30-year safe storage period prior to station dismantlement and site restoration. Activities associated with the placement of stations into a safe storage state include de-fuelling and de-watering of the nuclear reactors. OPG is responsible for the nuclear waste management and nuclear decommissioning obligations associated with the Bruce nuclear generating stations and includes the associated costs in its ARO. Pursuant to the lease agreement, Bruce Power must return the two Bruce stations to OPG together, in a de-fuelled and de-watered state. As such, these de-watering and de-fuelling costs are not part of OPG's ARO.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the obligation for these costs include an L&ILW DGR facility to be constructed and operated by OPG, as discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Project Excellence*. To estimate the liability for nuclear used fuel management, OPG has adopted

an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository for the long-term management of Canada's nuclear used fuel waste. The NWMO is responsible for the design and implementation of Canada's plan for the long-term management of used nuclear fuel.

The following costs are recognized as a liability on OPG's consolidated balance sheets:

- the present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives
- the present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed lives of the stations
- the present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs including construction of assumed waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, decommissioning strategy, and the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of such long-term duration and the evolving technology to handle nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

The estimates for the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. A comprehensive reassessment of all underlying assumptions and baseline cost estimates is performed periodically, at least once every five years, in line with the required ONFA reference plan update process. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of a net increase in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of a net decrease in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Resulting changes in the related asset retirement costs are capitalized as part of the carrying amount of nuclear fixed assets in service.

As of December 31, 2017, OPG recorded an increase of $188 million in the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E reflecting the extension in the Pickering GS accounting end-of-life assumptions. The adjustment did not impact net income for 2017. The adjustment is not expected to have a material impact on net income in 2018 as the associated impact on expenses is expected to be largely offset by OEB-authorized regulatory accounts. The change in accounting end-of-life assumptions for the Pickering GS and related regulatory accounts are discussed in further detail in the section, *Core Business, Strategy, and Outlook* under the heading, *Operational Excellence – Electricity Generation Production and Reliability*.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years.

The liability for nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2017 was $20,077 million (2016 – $19,103 million). As at December 31, 2017, the undiscounted cash flows of expenditures for OPG's Nuclear Liabilities in 2017 dollars are as follows:

| *(millions of dollars)* | **2018** | **2019** | **2020** | **2021** | **2022** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Expenditures for nuclear fixed asset removal and nuclear waste management [1] | 323 | 326 | 323 | 311 | 598 | 40,513 | 42,394 |

[1] The majority of the expenditures are expected to be reimbursed by the Nuclear Segregated Funds established by the ONFA. Any contributions required under the ONFA are not included in these undiscounted cash flows. Accounting for the Nuclear Segregated Funds is discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The liability for non-nuclear fixed asset removal was $344 million as at December 31, 2017 (2016 – $381 million). This liability primarily represents the present value of estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. OPG has updated the asset retirement obligations for the thermal generating stations as of December 31, 2017, based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions, and anticipated timing of these activities in line with current accounting end-of-life assumptions for the operating sites. For the former Nanticoke and Lambton generating stations, the update reflects the estimated cost of executing current decommissioning plans. For the currently operating sites, OPG recognized a decrease of $18 million in the non-nuclear fixed asset removal liabilities and associated asset retirement costs capitalized as part of the carrying value of PP&E as at December 31, 2017. For the Nanticoke and Lambton sites, the update resulted in a reduction in the non-nuclear fixed asset removal liabilities and a gain of approximately $12 million recorded in net income in the fourth quarter of 2017, in the Services, Trading, and Other Non-Generation segment.

For the purpose of measuring the non-nuclear fixed asset removal liability, thermal asset removal activities are assumed to take place approximately over the next one to 15 years. The amount of undiscounted estimated future cash flows associated with the thermal fixed asset removal liabilities is approximately $400 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

### Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

The fair value of financial assets and liabilities for which quoted prices in an active market are available, including exchange traded derivatives and other financial instruments, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund

administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that may affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used, primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying debt due to the direct relationship of the asset and the debt instruments that financed the acquisition.

OPG's use of financial instruments exposes the Company to certain risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found in the section, *Risk Management*.

## Recent Accounting Pronouncements Not Yet Adopted

The recent US GAAP accounting pronouncements related to revenue recognition, financial instruments, and leases are described below. Other recent accounting pronouncements applicable to OPG are outlined in Note 3 of OPG's 2017 audited consolidated financial statements.

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include generation revenue from regulated prices established by the OEB and revenue from generation assets under long-term contractual arrangements with the IESO. OPG has substantially completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the available-for-sale (AFS) classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. As at December 31, 2017, a cumulative loss of $9 million on OPG's AFS securities was recorded in AOCI, and will be reclassified to opening retained earnings effective January 1, 2018. There are no other significant differences to OPG's consolidated financial statements upon adoption of the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under Topic 840. The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company continues to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allows an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups, in order to evaluate and implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance will not have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of post-retirement benefits costs. Additionally, OPG already includes the service cost component of post-retirement benefit costs with other compensation costs, within the operations, maintenance and administration expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance will not affect the presentation of OPG's consolidated financial statements.

## RISK MANAGEMENT

### Overview

OPG faces various risks that could significantly impact the achievement of its strategic imperatives. The objective of risk management is to identify, assess and mitigate key risks, and to preserve and increase the value of the Shareholder's investment in the Company.

The Audit and Risk Committee is mandated to fulfill the oversight responsibilities of the Board of Directors for matters relating to the identification and management of the Company's key business risks. OPG's Enterprise Risk Management framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's strategic imperatives and business plan objectives. Formal risk management policies, procedures and systems are in place to identify, assess and mitigate risks to the Company. Senior management also establishes set limits for market risk, credit risk and energy trading activities of the Company.

The key risks to OPG's strategic imperatives are briefly described below. These are key risks that management believes could materially affect the Company's business, revenues, net income, assets or capital resources. There may be further risks and uncertainties that are not presently known, or that are not currently believed to be material, that may in the future adversely affect the Company's performance or financial condition.

### Risks to Achieving Operational Excellence

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance. The operational risks of a station are generally a function of its age, human performance, and the technology used.

Asset Conditions and Generation Variability

The uncertainty associated with electricity production by OPG's generating units is primarily driven by the condition of station components and systems, which are subject to the effects of aging and the manner in which the units operate. To safely operate the units to meet electricity system requirements, a unit could be derated resulting in reduced generation. The primary implications of these risks may include additional safety requirements, lower than expected generation and revenues, and higher operating or capital costs. To respond to this risk, OPG continues to:

- monitor performance and implement inspection and maintenance programs;
- identify future work required to sustain and, as appropriate, upgrade a station equipment; and
- undertake projects required to reliably operate within design and operating parameters.

Extension of Pickering Commercial Operation to 2024

Inability to extend Pickering operations to 2024 as planned would result in a reduction of OPG's future generation revenue and cash flows and lead to the advancement of station shutdown and decommissioning expenditures. This would include advancement of a significant reduction in OPG's workforce.

Risk factors for extended operations include the discovery of unexpected conditions, equipment failures, the state of critical plant components that are reaching end-of-life and a requirement for significant plant modifications. To mitigate these risks, OPG has implemented actions recommended from the technical assessments into the station's outage work program. OPG has also incorporated these actions into the comprehensive inspection and maintenance program as part of the station's life cycle management plans.

Supply Chain

OPG's ability to operate effectively is in part dependent upon timely access to equipment, materials, and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's operations and execution of major capital projects. OPG mitigates this risk, to the extent possible, through

contract negotiations, contract terms, vendor monitoring, diversification of supplier base and business continuity plans.

Cyber Security

OPG's operations depend, in part, on the efficient operation and management of the Company's complex information technology and operational systems in a secure, vigilant and resilient manner that minimizes cyber risks. Cyber security incidents may have an adverse impact on OPG's reputation, energy production, and public and employee safety.

Cyber security incidents have been on the rise over the last several years and this trend is expected to intensify as global reliance on technology increases. OPG has strategies in place to prepare for, respond to, and recover from cyber security incidents. OPG continuously monitors, assesses, and improves the effectiveness of its strategies and program considering leading industry practices and remains proactive in information and intelligence sharing to learn from, and adapt to the changing cyber environment. In 2017, the media reported several worldwide cyber-attacks, such as WannaCry and Petya ransomware attacks, which impacted multiple sectors including power and utilities. OPG's operational responses to those cyber-attacks were timely and effective, resulting in no or low operational impact to the Company.

As a registered Ontario market participant, OPG must comply with reliability standards that apply to the Bulk Electric System elements specified under North American Electric Reliability Corporation and the relevant Bulk Power System facilities as determined by the Northeast Power Coordinating Council. In addition, OPG's nuclear cyber assets are subject to CNSC licensing conditions and regulatory requirements. For other cyber assets not subject to applicable regulatory requirements, OPG has adopted a risk-based approach based on the National Institute of Standards and Technology cyber security framework to manage its cyber security.

Policies are in place to manage the Company's cyber risks and programs which are subject to oversight by management and the Board of Directors. OPG's current cyber programs primarily focus on the following:

- Improving cyber security protection, detection, incident response and recovery capabilities to reduce known or potential vulnerabilities
- Adopting industry leading practices to reduce third-party cyber security risks by introducing cyber security requirements into commercial agreements and improving the related governance
- Increasing the cyber security awareness and training level of the workforce through mandatory annual cyber security awareness training.

Regulatory Compliance

OPG is subject to extensive federal and provincial legislation and regulations by various entities such as the OEB, CNSC and the IESO.

The uncertainty associated with nuclear regulatory compliance is driven by plant aging, changes to technical codes, and challenges raised by the public at regulatory hearings, particularly in the areas of safety, environment and emergency preparedness. Addressing these requirements could add to the cost of operations, including replacement or modification of station components or additional requirements for waste management. In some instances, these requirements may result in a reduction or elimination of the productive capacity of a station.

The Darlington GS is operating under a ten-year CNSC operating licence, valid until November 30, 2025. The licence spans most of the planned duration of the Darlington Refurbishment project, which provides greater regulatory stability and reduces regulatory risk. As discussed in the section, *Core Business, Strategy, and Outlook* under the heading, *Nuclear Operations*, the plan to extend Pickering operations to 2024 is subject to the CNSC's approval of the Pickering licence renewal application and other regulatory requirements as set out by the CNSC.

Nuclear Waste Management

The handling, storage and disposal of nuclear waste exposes OPG to various risks that it manages in accordance with the applicable regulatory requirements. Additionally, the interim storage of nuclear waste is subject to rigorous oversight and monitoring.

Currently, there are no licenced facilities in Canada for the permanent disposal of used nuclear fuel or L&ILW. The risks to OPG's proposed L&ILW DGR for the safe long-term management of L&ILW are discussed below under the heading, *Risks to Achieving Project Excellence – Deep Geologic Repository for Low and Intermediate Level Waste*.

The NWMO has developed a process for moving forward with Adaptive Phased Management as the long-term solution for Canada's nuclear fuel waste. The Adaptive Phased Management plan contemplates the eventual long-term permanent disposal of radioactive nuclear fuel waste in a deep geologic repository. The NWMO is in the process of undertaking a multi-year site selection process for the used fuel deep geologic repository.

Hydroelectric Generating Stations

OPG's hydroelectric generation is exposed to risks associated with water flows and SBG conditions.

The extent to which OPG can operate its hydroelectric generation facilities depends upon the availability of water. Significant variability in weather, including impacts of climate change and the extreme weather associated with it, could affect water flows. Longer term changes in precipitation patterns and amounts, water temperatures and ambient air temperatures can impact the availability of water resources and resulting electricity production at OPG's hydroelectric stations. OPG is monitoring developments in climate science and adaptation activities, and continues to participate in climate change adaptation initiatives with all levels of government. For OPG's regulated hydroelectric generation, the financial impact of variability in electricity production due to differences between the forecast water conditions underpinning the hydroelectric regulated prices and the actual water conditions are captured in an OEB-approved regulatory account.

SBG continues to be an issue in Ontario when electricity supply exceeds demand. To manage SBG conditions, the IESO may require OPG to reduce hydroelectric generation. A regulatory account authorized by the OEB helps to mitigate the financial impact of electricity production foregone due to SBG conditions at OPG's regulated hydroelectric generating stations. The Company anticipates a declining trend in SBG due to reduced nuclear availability resulting from the refurbishment of the Darlington GS, future refurbishment of the Bruce generating stations, and the eventual shutdown of the Pickering GS.

Labour Relations

As of December 31, 2017, approximately 88 percent of OPG's regular labour force was represented by a union. The collective agreements with the PWU and The Society are due for renewal in 2018. There is a risk that OPG may not be able to negotiate terms that allow for unionized employee compensation levels consistent with those allowed for recovery by the OEB's December 2017 decision.

OPG's current collective agreement with the PWU expires on March 31, 2018 and renewal negotiations began in early 2018. In the event of a labour disruption by the PWU, OPG could face financial or reputational implications. OPG has contingency plans in place to minimize the impact.

The collective agreement between OPG and The Society expires on December 31, 2018 and renewal negotiations are expected to begin in mid-2018. The parties do not have the right to strike or lock-out. If the parties are unable to reach an agreement, the terms of the new collective agreement would be decided through interest mediation/ arbitration.

Human Resources

The development of new leaders and retention of staff in critical roles is a key factor to OPG's success. The risk associated with the alignment and availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. To mitigate this risk, OPG continues to focus on succession planning, leadership development and knowledge management programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by developing existing employees and hiring in specific areas, while continuing to leverage attrition through realignment of work and streamlining of processes, where appropriate.

Health and Safety

OPG's operations involve inherent occupational safety risks and hazards that could impact the achievement of the Company's health and safety goals. OPG is committed to continuous improvement and achievement of its ultimate goal of zero injuries through a formal enterprise-wide safety management system and by continuing to foster a strong health and safety culture among its employees and contractors. The safety management system serves to focus the Company on proactively managing safety risks and hazard exposures to employees and contractors. OPG also strategically engages with external parties for benchmarking and auditing. This ensures that OPG's safety management system achieves its intended results and maximizes the opportunity to incorporate program improvements.

Environment

OPG's operations and facilities are subject to environmental compliance obligations at the municipal, provincial and federal levels that include protection of land, water, air, living organisms and natural systems. A failure to comply with applicable environmental laws may result in enforcement actions, remediation actions or restrictions to operations. Changes in compliance obligations can result in new operational requirements and increased costs.

OPG has an ISO 14001 registered EMS to manage its environmental responsibilities. For further information, see discussion in the section, *Core Business, Strategy, and Outlook* under the heading, *Environmental Performance*.

OPG recognizes that efforts are required to plan for the impacts of climate change and has identified climate change adaptation as a strategic priority for the company. OPG monitors developments in climate science, adaptation activities, and potential changes to policy and regulatory requirements. OPG continues to work with stakeholders to better define adaptation requirements through analysis and understanding of impacts on watersheds, equipment and the electricity market. OPG uses a risk-based analysis to determine the extent of adaptation requirements needed to reduce the impact of climate change on its operations, and also collaborates with all levels of government and industry to increase the resiliency of the electricity infrastructure.

Business Continuity and Emergency Management

OPG may be exposed to natural, technological or human-caused hazards including significant events against which it is not fully insured or indemnified. These hazards have the potential to disrupt operations resulting in decreased generation revenue or additional costs to repair damages and restore operations.

OPG's business continuity program provides a framework to build resilience into critical business processes to ensure continued operation of critical business functions. OPG's emergency management program is designed to ensure that the Company can manage an emergency in a timely and effective manner. OPG's plans and implementation procedures identify immediate response actions to be taken to protect the health and safety of workers and the public, and to limit the impact of the incident on site security, production capability and the environment. The program elements are designed to meet legal and regulatory requirements.

## Risks to Achieving Project Excellence

OPG is undertaking several capital intensive projects with significant investments. There may be an adverse effect on the Company if it is unable to: obtain necessary approvals; raise the necessary funds; effectively manage the projects on time and on budget; or fully recover capital costs and earn an appropriate return on investment. These projects may also have a significant impact on OPG's borrowing capacity and credit rating. Some projects may be ultimately reassessed as being uneconomic. The risks associated with OPG's current major projects are described below.

Darlington Refurbishment

There are financial and reputational risk exposures for OPG if actual costs exceed the budget or if OPG does not meet the project schedule. In addition, failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment performance or useful life of the units. Failure to carry out unit refurbishments as planned may result in the Province exercising an off-ramp for subsequent refurbishment activities. OPG continues to apply lessons learned that have been captured on the execution of Unit 2 into the planning of future units.

There are a number of specific risks that OPG is managing and mitigating in relation to the Darlington Refurbishment project, which include OPG and vendor performance risks, delay or productivity risks, financial risks related to escalation of costs, technical risks such as equipment conditions resulting in additional scope, and execution risks.

OPG systematically manages the risks associated with the project through robust risk management practices to achieve project deliverables on time and budget, with quality. OPG engaged in an extensive five-year project planning phase to determine the project scope and to rigorously estimate costs. During this phase, OPG also took into account major lessons learned from other nuclear refurbishments and large scale, complex projects. In order to fully define the scope and material requirements for the project, the planning phase included the completion of detailed designs before proceeding with the execution of the unit refurbishments. Further risk mitigation has been implemented through the construction of a full scale model training reactor, which allows for simulations and training for unit refurbishment execution tasks.

A large portion of the work for the Darlington Refurbishment project is being performed by contractors and suppliers, including vendors that engineer, procure and construct components of the project. There is a risk that vendor capability, capacity and performance shortfalls may impact project objectives and deliverables. There is also an increased risk of contractor initiated safety events, which may impact OPG's reputation. OPG's risk management strategy aims to ensure that contractors operate safely and are held accountable with appropriate incentives and disincentives. Mitigating actions include:

- Collaborative training and planning with vendors on executing work safely;
- An enhanced human performance program;
- Increased field presence by supervisory staff; and
- Collaboration with Bruce Power to streamline processes and reduce burden on vendors.

OPG is also managing other ongoing risks that could potentially impact the project, including those related to continuity of skilled leaders within OPG and its vendor partners, as well as the availability of technical resources to support the project through execution.

Both the Company's management and Board of Directors have engaged independent, third-party oversight for the execution phase of the project.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG, with the support of Bruce County municipalities, is proposing to construct and operate a deep geologic repository for the safe long-term management of L&ILW. While broad local community support for the proposed

L&ILW DGR is stable, OPG continues its engagement with the SON towards securing support for the project and to formulate a response to the August 2017 request of the federal Minister of Environment and Climate Change. The timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

## Risks to Maintaining Financial Strength

Risks related to rate regulation, financial markets and long-term obligations could significantly impact OPG's financial performance. The Company is also exposed to risks such as weak electricity demand, displacement of generation by competitors and financial risk associated with energy trading.

### Rate Regulation

There is an inherent risk that regulated prices established by the OEB may not provide for the recovery of actual costs incurred by OPG's regulated operations or allow the regulated operations to earn an appropriate rate of return. This could occur if, in setting regulated prices, the OEB makes adjustments to forecasts submitted by OPG, if actual production and costs significantly differ from the forecasts approved by the OEB, or if OPG is unable to achieve cost-reductions in line with OEB-approved stretch factors included in regulated prices under incentive ratemaking. Differences between OPG's actual and forecast production and costs could be due to factors such as outages or project execution risks. In providing evidence in support of its applications for regulated prices, OPG aims to clearly demonstrate to the OEB that the costs for the regulated operations are reasonable, prudently incurred and should be fully recovered from customers.

Certain differences between elements of OEB-approved revenue requirements and OPG's actual results are recorded in OEB-authorized regulatory accounts for future review by the OEB. A number of these accounts may be subject to an OEB prudence review. There is uncertainty associated with the outcomes of future proceedings for the recovery or refund of these balances.

Consistent with the requirements of *Ontario Regulation 53/05*, a portion of the OEB-approved nuclear revenue requirements during the Darlington Refurbishment period may be deferred for future collection, with the objective of making more stable changes in OPG's production-weighted regulated prices year over year. There is a risk that the magnitude of the deferral ordered by the OEB will result in regulated prices that do not provide sufficient cash flow to the Company for meeting its financial objectives in an optimal manner, including maintaining the Company's investment grade credit rating. Maintaining adequate levels of credit metrics will support OPG's investment grade credit rating. As such, OPG has requested the OEB to consider the impact on its credit metrics when applying rate smoothing to OPG's regulated prices.

### Post-Employment Benefit Obligations

OPG's post-employment benefit obligations include pension, group life insurance, health care benefits, and LTD benefits. OPG's post-employment benefit obligations and costs and pension plan contributions could be materially affected in the future by numerous factors including: changes in discount rates, inflation rates and other actuarial assumptions; future investment returns; experience gains and losses; the funded status of the pension plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); changes in OPG's operations; and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most of OPG's employees and retirees, is a contributory defined benefit plan that is indexed to inflation up to a certain maximum. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. Future actuarial valuations could increase OPG's funding requirements due to market and economic-related conditions. A significant decline in the financial markets could trigger an immediate requirement to update the actuarial valuation based on declines in the funded status. OPG continues to assess the requirements for contributions to the registered pension plan, including the timing of future actuarial valuations. OPG's OPEB

obligations are not funded and the associated employee benefits are paid from cash flows provided by operating activities or other sources of liquidity.

Nuclear Liabilities and Nuclear Segregated Funds

As required by the CNSC, OPG is responsible for the management of used nuclear fuel and L&ILW and the decommissioning of its nuclear stations and waste management facilities. The cost estimates for OPG's nuclear waste management and decommissioning obligations are based on multiple underlying assumptions and estimates that are inherently uncertain and may evolve over time. The assumptions include station end-of-life dates, waste volumes, waste disposal methods, the timing of construction of assumed waste disposal facilities, waste packaging systems, decommissioning strategy and financial indicators. To address the inherent uncertainty, OPG undertakes to perform a comprehensive review of the underlying assumptions and baseline cost estimates at least once every five years, in line with the required reference plan update process under the ONFA.

The most recent comprehensive update of the nuclear waste management and decommissioning obligations was approved by the Province in December 2016 as part the 2017 ONFA Reference Plan. An approved ONFA reference plan determines OPG's contributions to the Nuclear Segregated Funds. Based on the 2017 ONFA Reference Plan, OPG is not currently required to make contributions to the Nuclear Segregated Funds. Contributions may be required in the future should the Nuclear Segregated Funds be in an underfunded position at the time of the next ONFA reference plan update.

Nuclear Segregated Funds are segregated under the ONFA in order to fund the long-term waste management, used fuel management and decommissioning expenditures. These funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA. Investments in the Nuclear Segregated Funds are allocated to certain asset classes including fixed income securities, domestic and international equity securities, pooled funds, infrastructure, agriculture and real estate. The rates of return earned on these segregated funds may vary depending on current and future financial market conditions. The asset mix of the funds is determined jointly by OPG and the Province in accordance with the ONFA.

Under ONFA, OPG bears the market risk related to the portion of the Nuclear Segregated Funds set aside for:

- decommissioning of the nuclear generating stations; and
- long-term management of the irradiated used fuel bundles in excess of the first 2.23 million bundles and L&ILW after the respective nuclear generating stations are shut down.

In accordance with the OEB-approved cost recovery methodology, the performance of the portion of the Nuclear Segregated Funds attributed to the Bruce nuclear generating stations is subject to the Bruce Lease Net Revenues Variance Account. Subject to the funded status of the funds discussed below, OPG's income is exposed to the rate of return risk related to the portion of the Nuclear Segregated Funds attributed to the Pickering and Darlington nuclear generating stations under the OEB-approved cost recovery methodology.

As discussed in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of the underlying life cycle funding liabilities per the most recently approved ONFA reference plan, as OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds. A reduction in the Nuclear Segregated Funds due to market conditions would first reduce the surplus in the respective funds before impacting OPG's net income. As such, the income statement impact of the rate of return risk is reduced when the Nuclear Segregated Funds are in a fully funded or overfunded position.

Contracted Generation

The Company's generating stations that operate under ESAs with the IESO or other long-term contracts are subject to several obligations, including but not limited to availability targets and must-offer obligations committing units to the

IESO market during specific hours, as specified in their respective contracts. OPG could incur penalties up to and including termination of the respective contract if these facilities fail to meet their contractual obligations. This risk is mitigated through implementation of maintenance, capital investment and other programs, and internal processes to communicate, educate, address and monitor contractual obligations and milestones.

OPG's owned and co-owned thermal generating stations operate under ESAs with the IESO or other long-term agreements. While OPG expects that these stations will continue to provide capacity to the market over the term of the respective agreements, there is a risk that, upon expiry of the current agreements, subsequent contracts for the stations may not be available or may not be financially viable. The Thunder Bay GS Biomass ESA is the first such contract scheduled to reach the end of its term, in early 2020.

Ontario Electricity Market

OPG's revenue can be impacted by external factors related to the electricity market including: the entrance of new participants into the Ontario market; the competitive actions of market participants; Ontario electricity demand; changes in the regulatory environment; and wholesale electricity prices in the interconnected markets.

The IESO is in the preliminary stages of a Market Renewal Program, which is a series of coordinated initiatives expected to result in a fundamental redesign of Ontario's electricity markets and may impact OPG depending on the market design that is implemented. The IESO's stated goal for the Market Renewal Program is to improve how electricity is priced, scheduled and procured in order to meet electricity system and participant needs reliably, transparently, efficiently and at lowest cost. OPG is actively participating in the Market Renewal Program stakeholdering process and continuing to collaborate with the IESO.

Ownership by the Province

The Province owns all of OPG's issued and outstanding common shares and Class A shares. Accordingly, the Province, as represented by the Ontario Ministry of Energy, has the authority to make appointments to OPG's Board of Directors. OPG could be subject to Shareholder direction under Section 108 of the OBCA, that can directly influence major decisions. These directions could include those related to project development, timing and strategy of applications for regulated prices, acquisitions and asset divestitures, financing and capital structure. As a result, OPG could be required to undertake activities that result in increased expenditures, or that reduce revenues or cash flows relative to the business activities or strategies that would have otherwise been undertaken. In addition, the obligation of OPG's Shareholder to respond to a broad range of matters in its role as the Government of Ontario may compete with OPG's commitment to maximize the return on the Shareholder's investment in the Company. This includes, but is not limited to, the Province's response to mitigate the impact of electricity prices on consumers.

Liquidity

OPG operates in a capital intensive business. Significant financial resources are required to fund major development and other capital improvement projects, including the Darlington Refurbishment project. In addition, the Company has other significant disbursement requirements including pension contributions, payments towards OPEB and other benefit plans, funding ongoing operations, debt maturities, purchases of subordinated debt issued by the Fair Hydro Trust and investments in new generating capacity and other business development opportunities. OPG must ensure that it has the financial capacity and sufficient access to cost effective financing sources to fund its capital requirements and other disbursements. In support of this objective, OPG utilizes multiple sources and forecasts availability of funds, actively monitors funding requirements and is focused on maintaining its investment grade credit rating. The Company's ability to arrange sufficient and cost-effective debt financing could be adversely affected by a number of factors, including financial market and general economic conditions, the regulatory environment in Ontario, the Company's results of operations and financial conditions, and the ratings assigned to the Company by credit rating agencies.

A discussion of corporate liquidity is included in the section, *Liquidity and Capital Resources*.

Commodity Markets

Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include using fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix and, as such, are subject to change as these forecasts are updated.

| | 2018 | 2019 | 2020 |
|---|---|---|---|
| Estimated fuel requirements hedged [1] | 73% | 68% | 65% |

[1] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to rate regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are primarily denominated in or tied to US dollars (USD). To manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts, in accordance with approved risk management policies. As at December 31, 2017, OPG had total foreign exchange contracts outstanding with a notional value of USD $5 million.

Trading

OPG's financial performance can be affected by its trading activities. OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2017, the VaR utilization ranged between $0.1 million and $0.4 million, compared to between nil and $1.5 million in 2016.

Credit

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2017:

| | All Counterparties | | Largest Counterparties | |
|---|---|---|---|---|
| **Credit Rating** [1] | **Number of Counterparties** [2] | **Potential Exposure** [3] *(millions of dollars)* | **Number of Counterparties** | **Potential Exposure** *(millions of dollars)* |
| Investment grade | 15 | 18 | 5 | 14 |
| IESO [4] | 1 | 354 | 1 | 354 |
| Total | 16 | 372 | 6 | 368 |

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure is an estimate of the short-term receivable amount arising from OPG's electricity sales into the IESO market. The credit exposure and associated receivable vary each month based on electricity sales. The monthly receivable from the IESO is typically paid to OPG in the subsequent month as per the IESO payment schedule.

Other major components of OPG's credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that the Company holds appropriate collateral or other forms of security.

Government Legislation and Regulation Changes

OPG's core business and strategy may be impacted by changes in federal and provincial legislation and regulations. Matters that are subject to regulation include, among others, rate regulation, electricity generating operations, nuclear waste management and nuclear decommissioning, the Ontario electricity market and taxation. Regulatory bodies may change or enact regulations or rules that could increase OPG's costs, decrease OPG's revenue, or limit the Company's ability to recover appropriate costs or earn a return on the assets.

The next Ontario provincial election is set to take place in June 2018 and electricity rates are a focus of each major political party's platform. Depending on the outcome of the election, there may be significant legislative changes that could impact OPG.

To mitigate legislative risks, OPG monitors and actively engages with the federal and provincial governments in order to determine if future legislation will impact the Company.

Litigation

OPG or its subsidiaries are involved in various legal proceedings covering a range of matters arising out of their business activities. Each of these matters is subject to various uncertainties and some of these matters may be resolved unfavourably. It is the Company's belief that the resolution of these matters is not likely to have a material adverse impact on its financial position. Refer to Note 16 of OPG's 2017 audited consolidated financial statements under the heading, *Litigation* for further details.

## Risks to Maintaining Social Licence

OPG is exposed to risks associated with its social licence and public profile due to changes in the opinions of various stakeholders, including Ontario electricity customers, local communities, government agencies, and partners, such as Indigenous communities.

Maintaining public trust and meeting stakeholders and Indigenous communities' expectations are critical to OPG's success. OPG focuses on building and maintaining its social licence and corporate reputation through safe, reliable,

environmentally-responsible operations as well as corporate citizenship initiatives across the province. The inability to maintain safe, reliable operations could negatively impact OPG's reputation and result in a loss of public support.

Ontario's Fair Hydro Plan

OPG's reputation could potentially be adversely impacted through its involvement as the Financial Services Manager under the Fair Hydro Act, and through stakeholder opinions related to this involvement.

Indigenous Communities

The quality of OPG's relationships and the outcome of negotiations with Indigenous communities may impact OPG's project and financial performance, as well as its social licence to operate.

OPG may be subject to claims by Indigenous communities. These claims stem from projects and generation development related to the operations of OPG and historic operations of OPG's predecessor company, Ontario Hydro, which may have impacted the Aboriginal and/or Treaty rights of Indigenous communities.

OPG has an Indigenous Relations Policy, which sets out the Company's commitment to proactively build and maintain positive relationships with Indigenous communities. OPG has been successful in working collaboratively with Indigenous communities to resolve a number of past grievances. However, the outcome of ongoing and any future negotiations depends on a number of factors, including legislation, regulations and precedents created by court rulings, which are subject to change over time.

**RELATED PARTY TRANSACTIONS**

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

| | 2017 | | 2016 | |
|---|---|---|---|---|
| *(millions of dollars)* | **Income** | **Expense** | **Income** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **8** | **-** | 6 | - |
| Services | **1** | **10** | 1 | 5 |
| Dividends | **7** | **-** | 6 | - |
| Province of Ontario | | | | |
| Change in Decommissioning Segregated Fund amount due to Province [1] | **-** | **456** | - | 192 |
| Change in Used Fuel Segregated Fund amount due to Province [1] | **-** | **591** | - | 235 |
| Hydroelectric gross revenue charge | **-** | **110** | - | 120 |
| ONFA guarantee fee | **-** | **8** | - | 8 |
| Other | **-** | **2** | - | - |
| OEFC | | | | |
| Hydroelectric gross revenue charge | **-** | **216** | - | 203 |
| Interest expense on long-term notes | **-** | **158** | - | 169 |
| Income taxes, net of investment tax credits | **-** | **246** | - | 104 |
| IESO | | | | |
| Electricity related revenue | **4,802** | **-** | 5,082 | - |
| Earnings from Fair Hydro Trust | **1** | **-** | - | - |
| | **4,819** | **1,797** | 5,095 | 1,036 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivables, financing receivables, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| *(millions of dollars)* | December 31 2017 | 2016 |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO – Electricity related receivables | **354** | 421 |
| IESO – Fair Hydro Trust [1] | **7** | - |
| OEFC | **-** | 1 |
| PEC | **4** | 4 |
| Province of Ontario | **3** | 2 |
| Financing receivables | | |
| IESO – Fair Hydro Trust | **1,179** | - |
| Available-for-sale securities | | |
| Hydro One shares | **188** | 212 |
| Accounts payable and accrued charges | | |
| Hydro One | **1** | - |
| OEFC | **52** | 61 |
| Province of Ontario | **9** | 2 |
| IESO − Electricity related payables | **5** | 2 |
| IESO – Fair Hydro Trust | **3** | - |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,195** | 3,295 |

[1] Balance consists of unbilled revenue as at December 31, 2017

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,502 million of Province of Ontario bonds (2016 − $1,650 million) and $9 million of Province of Ontario treasury bills (2016 − $2 million). As of December 31, 2017, the registered pension fund held $1 million in Province of Ontario treasury bills (2016 − $271 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Act is invalid or unconstitutional.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer (President and CEO) and the Chief Financial Officer (CFO), are responsible for maintaining Disclosure Controls and Procedures (DC&P) and Internal Controls over Financial Reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

There were no changes in OPG's ICOFR during the year ended December 31, 2017 that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Management, including the President and CEO and the CFO, concluded that, as of December 31, 2017, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings*) were effective.

## FOURTH QUARTER

### Discussion of Results

| *(millions of dollars)* (unaudited) | Three Months Ended December 31 2017 | 2016 |
|---|---|---|
| Revenue | **1,619** | 1,388 |
| Fuel expense | **171** | 186 |
| Gross margin | **1,448** | 1,202 |
| Operations, maintenance and administration | **770** | 686 |
| Depreciation and amortization | **162** | 316 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **251** | 233 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(222)** | (126) |
| Earnings from Fair Hydro Trust | **(1)** | - |
| Income from investments subject to significant influence | **(9)** | (9) |
| Property taxes | **10** | 11 |
| Restructuring | **-** | 6 |
| | **961** | 1,117 |
| Income before other losses, interest, and income taxes | **487** | 85 |
| Other losses | **1** | 6 |
| Income before interest and income taxes | **486** | 79 |
| Net interest expense | **39** | 28 |
| Income before income taxes | **447** | 51 |
| Income tax expense | **81** | 59 |
| Net income (loss) | **366** | (8) |
| Net income (loss) attributable to the Shareholder | **362** | (13) |
| Net income attributable to non-controlling interest | **4** | 5 |

Net income attributable to the Shareholder for the fourth quarter was $362 million, compared to a net loss of $13 million for the same quarter in 2016.

Income before interest and income taxes was $486 million for the fourth quarter of 2017, an increase of $407 million compared to income before interest and income taxes of $79 million for the same period in 2016. The following summarizes the significant factors which contributed to the variance:

*Significant factors that increased income before interest and income taxes:*

- Revenue from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments of approximately $480 million recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on OPG's application for new regulated prices with a retrospective effective date of June 1, 2017.
- Higher earnings of $77 million from the Regulated – Nuclear Waste Management segment, primarily due to higher earnings from the Nuclear Segregated Funds, partially offset by an increase in accretion expense on the Nuclear Liabilities. Higher earnings from the Nuclear Segregated Funds reflected a reduction in earnings recorded in the fourth quarter of 2016 to reflect an accounting adjustment to limit Nuclear Segregated Funds assets to the underlying funding liabilities per the 2017 ONFA Reference Plan, as well as earnings recorded during the fourth quarter of 2017 at the growth rate of the present value of the funding liabilities being higher than earnings from market returns on fund assets and, for a portion of the Used Fuel Segregated Fund, the Province's rate of return guarantee in the fourth quarter of 2016. The increase in accretion expense was mainly due to the impact of adjustments to the Nuclear Liabilities recorded at the end

of 2015 and at the end of 2016 no longer being offset by regulatory accounts, as these impacts were incorporated into the OEB's decision on new regulated prices and therefore the corresponding retrospective revenue increase recorded in the Regulated – Nuclear Generation segment in the fourth quarter of 2017.

*Significant factors that decreased income before interest and income taxes:*

- Lower revenue from the nuclear base regulated price of approximately $55 million, partially offset by a decrease in fuel expense of $9 million, reflecting lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. The lower nuclear generation was primarily due to a higher number of planned outage days at the Pickering GS in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017.
- Higher OM&A expenses of $84 million, mainly in the Regulated – Nuclear Generation segment, reflecting planned expenditures related to the major maintenance activities occurring at the nuclear stations and higher nuclear project expenses.

The increase in revenue in the fourth quarter of 2017, compared to the same quarter in 2016, was partially offset by the impact of the expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016. This impact was largely offset by a decrease in the amortization expense related to regulatory account balances.

The increase in income tax expense during the fourth quarter of 2017, compared to the same quarter in 2016, was primarily due to higher income before income taxes, partially offset by a higher amount of income tax expense deferred as regulatory assets in 2017.

### Average Sales Prices

The average sales price for the Regulated – Nuclear Generation segment during the fourth quarter of 2017 was 11.0 ¢/kWh, compared to 6.9 ¢/kWh during the same quarter in 2016. The increase in the average sales price was primarily due to the revenue related to the June 1, 2017 to December 31, 2017 period recorded in the fourth quarter of 2017 to reflect the OEB's December 2017 decision on new regulated prices. As this incremental revenue reflects the impact of a retrospective increase in regulated prices for a seven-month period in 2017, the average sales price for the Regulated – Nuclear Generation segment will be lower in 2018 than in the fourth quarter of 2017. The expiry of an OEB-authorized nuclear rate rider of $10.84/MWh for the recovery of regulatory account balances on December 31, 2016 partially offset the increase in the average sales price during the fourth quarter of 2017, compared to the same period in 2016.

The average sales price for the Regulated – Hydroelectric segment during the fourth quarter of 2017 was 4.3 ¢/kWh, compared to 4.4 ¢/kWh during the same period in 2016. The decrease in this average sales price was primarily due to the expiry of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of regulatory account balances on December 31, 2016.

## Electricity Generation

OPG's electricity generation for the three months ended December 31, 2017 and 2016 was as follows:

| *(TWh)* | Three Months Ended December 31 2017 | 2016 |
|---|---|---|
| Regulated – Nuclear Generation | **10.1** | 11.0 |
| Regulated – Hydroelectric | **7.2** | 6.7 |
| Contracted Generation Portfolio [1] | **0.8** | 0.6 |
| Total OPG electricity generation | **18.1** | 18.3 |
| Total electricity generation by all other generators in Ontario [2] | **18.8** | 18.9 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the IESO, minus OPG electricity generation.

The decrease in OPG's electricity generation of 0.2 TWh during the fourth quarter of 2017, compared to the same quarter in 2016, was mainly due to lower electricity generation of 0.9 TWh from the Regulated – Nuclear Generation segment. This was mainly the result of a higher number of planned outage days at the Pickering GS in 2017 as well as the refurbishment of Unit 2 at the Darlington GS, which began in mid-October 2016 and continued for all of 2017. This was largely offset by higher electricity generation from the Regulated – Hydroelectric and Contracted Generation Portfolio segments, mainly due to higher water flows on the eastern and northeastern Ontario river systems.

Ontario's electricity demand as reported by the IESO was 33.6 TWh during the fourth quarter of 2017, compared to 33.2 TWh during the fourth quarter of 2016. Ontario's electricity demand excludes electricity exports out of the province.

## Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2017 was $246 million, compared to $606 million for the same period in 2016. The decrease in cash flow provided by operating activities was primarily due to lower generation revenue receipts and higher OM&A expenditures during the fourth quarter of 2017. Lower generation revenue receipts mainly reflected the expiry of rate riders for the recovery of OEB-approved balances in regulatory accounts on December 31, 2016. The decrease was partially offset by lower contributions to the Nuclear Segregated Funds.

Cash flow used in investing activities during the three months ended December 31, 2017 was $1,758 million, compared to $666 million during the same period in 2016. The increase in cash flow used in investing activities was primarily due to the Fair Hydro Trust's acquisition of the first tranche of Investment Interest from the IESO in December 2017.

Cash flow provided by financing activities during the three months ended December 31, 2017 was $1,466 million, compared to cash flow used in financing activities of $180 million for the same period in 2016. The increase in cash flow provided by financing activities was primarily due to the issuance of Fair Hydro Trust senior notes and Class A shares in December 2017 and higher net issuance of short-term debt and long-term corporate debt in the fourth quarter of 2017.

## QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected annual financial information for the last three years and financial information for each of the eight most recently completed quarters. This information is derived from OPG's unaudited interim consolidated financial statements and the audited annual consolidated financial statements, and has been prepared in accordance with US GAAP.

### Annual Financial Information

| *(millions of dollars – except where noted)* | 2017 | 2016 | 2015 |
|---|---|---|---|
| Revenue | **5,158** | 5,653 | 5,476 |
| Net income attributable to the Shareholder | **860** | 436 | 402 |
| Earnings per share, attributable to the Shareholder *(dollars)* | **$3.35** | $1.70 | $1.57 |
| Total assets | **48,822** | 44,372 | 44,250 |
| Total long-term liabilities | **34,933** | 31,460 | 32,404 |
| Weighted average shares outstanding *(millions)* | **256.7** | 256.3 | 256.3 |

### Quarterly Financial Information

| *(millions of dollars – except where noted)* *(unaudited)* | 2017 Quarters Ended | | | | |
|---|---|---|---|---|---|
| | **December 31** | **September 30** | **June 30** | **March 31** | **Total** |
| Revenue | **1,619** | **1,217** | **1,146** | **1,176** | **5,158** |
| Net income | **366** | **140** | **307** | **68** | **881** |
| Less: Net income attributable to non-controlling interest | **4** | **9** | **4** | **4** | **21** |
| Net income attributable to the Shareholder | **362** | **131** | **303** | **64** | **860** |
| **Earnings per share, attributable to the Shareholder *(dollars)*** | **$1.41** | **$0.51** | **$1.18** | **$0.25** | **$3.35** |

### Quarterly Financial Information

| *(millions of dollars – except where noted)* *(unaudited)* | 2016 Quarters Ended | | | | |
|---|---|---|---|---|---|
| | **December 31** | **September 30** | **June 30** | **March 31** | **Total** |
| Revenue | 1,388 | 1,400 | 1,387 | 1,478 | 5,653 |
| Net (loss) income | (8) | 198 | 135 | 128 | 453 |
| Less: Net income attributable to non-controlling interest | 5 | 4 | 3 | 5 | 17 |
| Net (loss) income attributable to the Shareholder | (13) | 194 | 132 | 123 | 436 |
| **Earnings per share, attributable to the Shareholder *(dollars)*** | ($0.05) | $0.76 | $0.51 | $0.48 | $1.70 |

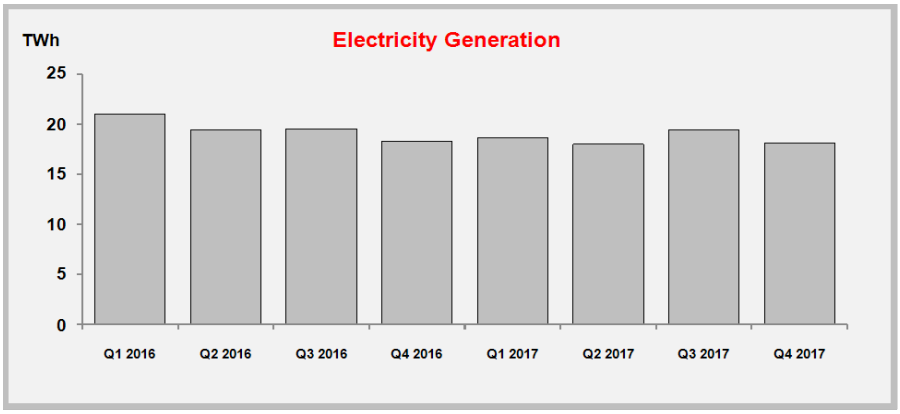
## Trends

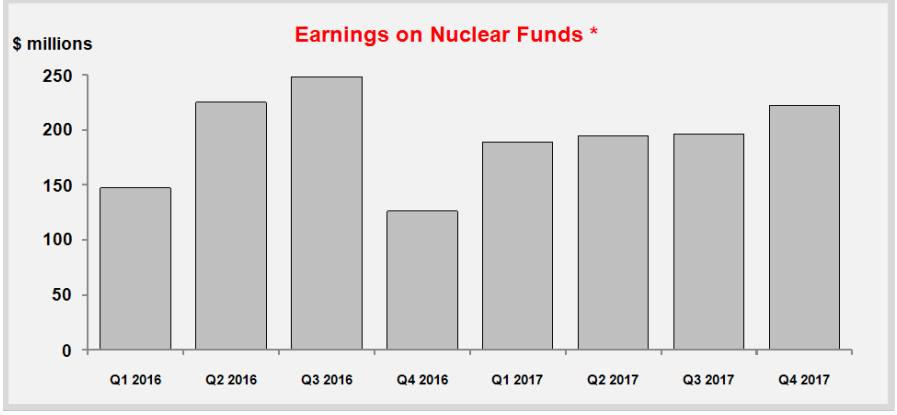
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory accounts authorized by the OEB.

The outage cycle at each of OPG's nuclear generating stations determines the number and frequency of planned outages in a particular year. The outage cycle is designed to ensure the continued safe and reliable long-term operations of the plant and its compliance with CNSC regulatory requirements. The frequency of planned outages under the outage cycle may result in year-over-year variability in OPG's operating results, including the impact on revenue and OM&A expenses. In addition, the timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced in 2017 as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is scheduled to continue until early 2020.

OPG's financial results are also affected by earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account. The volatility of earnings on the Nuclear Segregated Funds is mitigated by their funded status.




*net of regulatory variance account

## SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

**(1) ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period.

ROE Excluding AOCI is measured over a 12-month period and is calculated as follows for the period ended December 31:

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| ROE Excluding AOCI | | |
| Net income attributable to the Shareholder | **860** | 436 |
| Divided by: Average equity attributable to the Shareholder, excluding AOCI | **11,351** | 10,442 |
| **ROE Excluding AOCI *(percent)*** | **7.6** | 4.2 |

**(2) FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows for the period ended December 31:

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| FFO before interest | | |
| Cash flow provided by operating activities | **944** | 1,817 |
| Add: Interest paid | **258** | 269 |
| Less: Interest capitalized to fixed and intangible assets | **(162)** | (141) |
| Less: Changes to non-cash working capital balances | **(54)** | (180) |
| FFO before interest | **986** | 1,765 |
| Adjusted interest expense | | |
| Net interest expense | **95** | 120 |
| Add: Interest income | **9** | 7 |
| Add: Interest capitalized to fixed and intangible assets | **162** | 141 |
| Add: Interest related to regulatory assets and liabilities | **30** | 30 |
| Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1] | **-** | 45 |
| Adjusted interest expense | **296** | 343 |
| **FFO Adjusted Interest Coverage *(times)*** | **3.3** | 5.1 |

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

**(3) Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

Enterprise TGC per MWh is calculated as follows for the year ended December 31:

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| Enterprise TGC | | |
| Total OM&A expenses | **2,824** | 2,747 |
| Total fuel expense | **689** | 727 |
| Total capital expenditures | **1,926** | 1,704 |
| Less: Darlington Refurbishment capital and OM&A costs | **(1,285)** | (1,022) |
| Less: Other generation development project capital and OM&A costs | **(65)** | (163) |
| (Less) Add: OM&A and fuel expenses (refundable through) deferred in regulatory accounts | **(1)** | 62 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(57)** | (67) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **69** | 49 |
| Less: OM&A expenses ancillary to electricity generation business | **(18)** | (28) |
| Other adjustments | **(43)** | (19) |
| | **4,039** | 3,990 |
| Adjusted electricity generation *(TWh)* | | |
| Total OPG electricity generation | **74.1** | 78.2 |
| Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities | **5.6** | 4.1 |
| | **79.7** | 82.3 |
| **Enterprise TGC per MWh *($/MWh)*** [1] | **50.66** | **48.45** |

[1] Amounts may not calculate due to rounding.

**(4) Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

Nuclear TGC per MWh is calculated as follows for the year ended December 31:

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| Nuclear TGC | | |
| Regulated – Nuclear Generation OM&A expenses | **2,293** | 2,210 |
| Regulated – Nuclear Generation fuel expense | **284** | 315 |
| Regulated – Nuclear Generation capital expenditures | **1,631** | 1,338 |
| Less: Darlington Refurbishment capital and OM&A costs | **(1,285)** | (1,022) |
| Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory accounts | **35** | 81 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(57)** | (67) |
| Less: Regulated – Nuclear Generation OM&A expenses ancillary to electricity generation business | **(6)** | (10) |
| Other adjustments | **(10)** | (4) |
| | **2,885** | 2,841 |
| Nuclear electricity generation *(TWh)* | **40.7** | 45.6 |
| **Nuclear TGC per MWh *($/MWh)*** [1] | **70.95** | 62.30 |

[1] Amounts may not calculate due to rounding.

**(5) Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

Hydroelectric TGC per MWh is calculated as follows for the year ended December 31:

| *(millions of dollars – except where noted)* | **2017** | **2016** |
|---|---|---|
| Hydroelectric TGC | | |
| Regulated – Hydroelectric OM&A expenses | **330** | 325 |
| Regulated – Hydroelectric fuel expense | **351** | 353 |
| Contracted Generation Portfolio OM&A expenses | **169** | 178 |
| Contracted Generation Portfolio fuel expense | **53** | 58 |
| Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures | **221** | 330 |
| Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs | **(63)** | (158) |
| Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio | **(166)** | (177) |
| Less: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory accounts | **(36)** | (24) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **69** | 49 |
| Other adjustments | **(1)** | (1) |
| | **927** | 933 |
| Adjusted hydroelectric electricity generation *(TWh)* | | |
| Regulated – Hydroelectric electricity generation | **30.7** | 29.5 |
| Contracted Generation Portfolio electricity generation | **2.7** | 3.1 |
| Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities | **5.5** | 4.0 |
| | **38.9** | 36.6 |
| **Hydroelectric TGC per MWh *($/MWh)*** [1] | **23.79** | 25.49 |

[1] Amounts may not calculate due to rounding.

**(6) Gross margin** is defined as revenue less fuel expense**.**

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# ONTARIO POWER GENERATION INC.

# CONSOLIDATED FINANCIAL STATEMENTS

**DECEMBER 31, 2017**



# STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s (OPG) management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis (MD&A).

The consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles (US GAAP). The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information, we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect the reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, and risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of the financial information, we maintain and rely on a comprehensive system of internal controls and internal audits, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal controls over transactions, assets and records. We also regularly test internal controls. These controls and testing are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer (CEO) and the Chief Financial Officer (CFO), is responsible for maintaining disclosure controls and procedures (DC&P) and internal controls over financial reporting (ICOFR). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements in accordance with US GAAP.

An evaluation of the effectiveness of the design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2017. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the Ontario Securities Commission, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Risk Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major areas of financial risk, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Risk Committee, had direct and full access to the Audit and Risk Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.

**Jeff Lyash (signed)**
*President and Chief Executive Officer*

**Ken Hartwick (signed)**
*Chief Financial Officer and Senior Vice President – Finance*

March 8, 2018

# INDEPENDENT
# AUDITORS' REPORT

**To the Shareholder of Ontario Power Generation Inc.**

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2017 and 2016, and the consolidated statements of income, comprehensive income, cash flows and changes in shareholder's equity for the years then ended, and a summary of significant accounting policies and other explanatory information.

**Management's Responsibility for the Consolidated Financial Statements**

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

**Auditors' Responsibility**

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

**Opinion**

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2017 and 2016, and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Toronto, Canada

March 8, 2018

Ernst & Young LLP (signed)

Chartered Professional Accountants,
Licensed Public Accountants

# CONSOLIDATED STATEMENTS OF INCOME

| **Years Ended December 31**<br>*(millions of dollars except where noted)* | **2017** | **2016** |
|---|---|---|
| **Revenue** | **5,158** | 5,653 |
| Fuel expense | **689** | 727 |
| **Gross margin** | **4,469** | 4,926 |
| Operations, maintenance and administration | **2,824** | 2,747 |
| Depreciation and amortization *(Note 4)* | **679** | 1,257 |
| Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)* | **960** | 929 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)* | **(801)** | (746) |
| Earnings from Fair Hydro Trust *(Note 17)* | **(1)** | - |
| Income from investments subject to significant influence | **(38)** | (37) |
| Property taxes | **40** | 46 |
| Restructuring | **-** | 6 |
| | **3,663** | 4,202 |
| **Income before other gains, interest and income taxes** | **806** | 724 |
| Other gains *(Note 4)* | **379** | 17 |
| **Income before interest and income taxes** | **1,185** | 741 |
| Net interest expense *(Note 6)* | **95** | 120 |
| **Income before income taxes** | **1,090** | 621 |
| Income tax expense *(Note 9)* | **209** | 168 |
| **Net income** | **881** | 453 |
| **Net income attributable to the Shareholder** | **860** | 436 |
| Net income attributable to non-controlling interest | **21** | 17 |
| **Basic and diluted earnings per share** *(dollars) (Note 15)* | **3.35** | 1.70 |

*See accompanying notes to the consolidated financial statements*

# CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| **Years Ended December 31**<br>*(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Net income** | **881** | 453 |
| **Other comprehensive (loss) income, net of income taxes** *(Note 10)* | | |
| Actuarial loss on remeasurement of liabilities for pension and other post-employment benefits [1] | **(23)** | (6) |
| Reclassification to income of amounts related to pension and other post-employment benefits [2] | **10** | 12 |
| Reclassification to income of losses on derivatives designated as cash flow hedges [3] | **18** | 19 |
| Unrealized loss on available-for-sale securities [4] | **(8)** | (1) |
| Other comprehensive (loss) income for the year | **(3)** | 24 |
| **Comprehensive income** | **878** | 477 |
| **Comprehensive income attributable to the Shareholder** | **857** | 460 |
| Comprehensive income attributable to non-controlling interest | **21** | 17 |

[1] Net of income tax recovery of $7 million and $2 million for 2017 and 2016, respectively.

[2] Net of income tax expenses of $3 million and $4 million for 2017 and 2016, respectively.

[3] Net of income tax expenses of $2 million for each of 2017 and 2016.

[4] Net of income tax recovery of $2 million and nil for 2017 and 2016, respectively.

*See accompanying notes to the consolidated financial statements*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| Years Ended December 31<br>*(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| **Operating activities** | | |
| Net income | **881** | 453 |
| Adjust for non-cash items: | | |
| Depreciation and amortization *(Note 4)* | **679** | 1,257 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **960** | 929 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(801)** | (746) |
| Pension and other post-employment benefit costs *(Note 11)* | **412** | 464 |
| Deferred income taxes | **19** | (36) |
| Mark-to-market on derivative instruments *(Note 12)* | **(3)** | 3 |
| Provision for used nuclear fuel and low and intermediate level nuclear waste | **116** | 118 |
| Regulatory assets and liabilities | **(558)** | (170) |
| Provision for materials and supplies | **33** | 42 |
| Other gains | **(371)** | - |
| Other | **1** | (25) |
| | **1,368** | 2,289 |
| Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 8)* | **-** | (150) |
| Expenditures on fixed asset removal and nuclear waste management | **(313)** | (275) |
| Reimbursement of eligible expenditures on nuclear fixed asset removal and nuclear waste management | **79** | 70 |
| Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans | **(322)** | (363) |
| Expenditures on restructuring | **(4)** | (6) |
| Distributions received from investments subject to significant influence | **50** | 52 |
| Net changes to other long-term assets and liabilities | **32** | 20 |
| Net changes to non-cash working capital balances *(Note 18)* | **54** | 180 |
| **Cash flow provided by operating activities** | **944** | 1,817 |
| **Investing activities** | | |
| Acquisition of Fair Hydro Trust financing receivables *(Note 19)* | **(1,179)** | - |
| Purchase of available-for-sale securities | **-** | (213) |
| Proceeds from deposit note | **70** | 110 |
| Net proceeds from sale of property, plant and equipment | **484** | - |
| Investment in property, plant and equipment and intangible assets | **(1,853)** | (1,816) |
| **Cash flow used in investing activities** | **(2,478)** | (1,919) |
| **Financing activities** | | |
| Issuance of Class A shares *(Note 14)* | **519** | - |
| Issuance of OPG long-term debt *(Note 6)* | **1,301** | 334 |
| Repayment of OPG long-term debt | **(1,103)** | (273) |
| Issuance of Fair Hydro Trust long-term debt *(Note 6)* | **601** | - |
| Distribution to non-controlling interest | **(15)** | (14) |
| Capital contribution from non-controlling interest | **19** | - |
| Issuance of short-term debt | **1,960** | 3,108 |
| Repayment of short-term debt | **(1,700)** | (3,331) |
| **Cash flow provided by (used in) financing activities** | **1,582** | (176) |
| Net increase (decrease) in cash and cash equivalents | **48** | (278) |
| **Cash and cash equivalents, beginning of year** | **186** | 464 |
| **Cash and cash equivalents, end of year** | **234** | 186 |

*See accompanying notes to the consolidated financial statements*

# CONSOLIDATED BALANCE SHEETS

| As at December 31<br>*(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| **Assets** | | |
| **Current assets** | | |
| Cash and cash equivalents [1] | **234** | 186 |
| Available-for-sale securities | **188** | 212 |
| Receivables from related parties *(Note 19)* | **369** | 429 |
| Nuclear fixed asset removal and nuclear waste management funds *(Note 8)* | **23** | 24 |
| Fuel inventory | **309** | 310 |
| Materials and supplies | **103** | 100 |
| Prepaid expenses | **192** | 198 |
| Other current assets | **146** | 298 |
| | **1,564** | 1,757 |
| **Property, plant and equipment** *(Note 4)* | **29,950** | 29,315 |
| Less: accumulated depreciation | **8,628** | 9,317 |
| | **21,322** | 19,998 |
| **Intangible assets** *(Note 4)* | **565** | 503 |
| Less: accumulated amortization | **432** | 404 |
| | **133** | 99 |
| **Other assets** | | |
| Nuclear fixed asset removal and nuclear waste management funds *(Note 8)* | **16,701** | 15,960 |
| Financing receivables *(Note 19)* | **1,179** | - |
| Long-term materials and supplies | **355** | 345 |
| Regulatory assets *(Note 5)* | **7,231** | 5,855 |
| Investments subject to significant influence *(Note 20)* | **309** | 321 |
| Other long-term assets | **28** | 37 |
| | **25,803** | 22,518 |
| | **48,822** | 44,372 |

[1] Includes $4 million restricted for Fair Hydro Trust purposes as at December 31, 2017 (December 31, 2016 – nil).

*See accompanying notes to the consolidated financial statements*

# CONSOLIDATED BALANCE SHEETS

| As at December 31<br>*(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| **Liabilities** | | |
| **Current liabilities** | | |
| Accounts payable and accrued charges | **1,228** | 1,164 |
| Short-term debt *(Note 7)* | **260** | 2 |
| Deferred revenue due within one year | **12** | 12 |
| Long-term debt due within one year *(Note 6)* | **398** | 1,103 |
| Income taxes payable | **80** | 123 |
| | **1,978** | 2,404 |
| **Long-term debt** *(Note 6)* | **5,921** | 4,417 |
| **Other liabilities** | | |
| Fixed asset removal and nuclear waste management liabilities *(Note 8)* | **20,421** | 19,484 |
| Pension liabilities *(Note 11)* | **3,423** | 3,012 |
| Other post-employment benefit liabilities *(Note 11)* | **3,092** | 2,897 |
| Long-term accounts payable and accrued charges | **252** | 213 |
| Deferred revenue | **351** | 298 |
| Deferred income taxes *(Note 9)* | **879** | 829 |
| Regulatory liabilities *(Note 5)* | **594** | 310 |
| | **29,012** | 27,043 |
| **Equity** | | |
| Common shares [1] *(Note 14)* | **5,126** | 5,126 |
| Class A shares [2] *(Note 14)* | **519** | - |
| Retained earnings | **6,396** | 5,534 |
| Accumulated other comprehensive loss *(Note 10)* | **(295)** | (295) |
| **Equity attributable to the Shareholder** | **11,746** | 10,365 |
| Equity attributable to non-controlling interest *(Note 22)* | **165** | 143 |
| **Total equity** | **11,911** | 10,508 |
| | **48,822** | 44,372 |

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2017 and December 31, 2016.

[2] 12,217,616 Class A shares outstanding at a stated value of $519 million as at December 31, 2017 (December 31, 2016 − nil).

Commitments and Contingencies *(Notes 6, 9, 11 and 16)*

*See accompanying notes to the consolidated financial statements*

On behalf of the Board of Directors:

**Bernard Lord (signed)**
Board Chair

**M. George Lewis (signed)**
Director

# CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

| **Years Ended December 31**<br>*(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Common shares** *(Note 14)* | **5,126** | 5,126 |
| **Class A shares** *(Note 14)* | | |
| Balance at beginning of year | **-** | - |
| Issuance of Class A shares | **519** | - |
| Balance at end of year | **519** | - |
| **Retained earnings** | | |
| Balance at beginning of year | **5,534** | 5,098 |
| Net income attributable to the Shareholder | **860** | 436 |
| Reclassification of non-controlling interest on change in ownership interest *(Note 22)* | **2** | - |
| Balance at end of year | **6,396** | 5,534 |
| **Accumulated other comprehensive loss, net of income taxes** | | |
| Balance at beginning of year | **(295)** | (319) |
| Other comprehensive (loss) income | **(3)** | 24 |
| Reclassification of non-controlling interest on change in ownership interest *(Note 22)* | **3** | - |
| Balance at end of year | **(295)** | (295) |
| **Equity attributable to the Shareholder** | **11,746** | 10,365 |
| **Equity attributable to non-controlling interest** | | |
| Balance at beginning of year | **143** | 140 |
| Equity contribution from non-controlling interest *(Note 22)* | **21** | - |
| Reclassification of non-controlling interest on change in ownership interest *(Note 22)* | **(5)** | - |
| Distribution to non-controlling interest | **(15)** | (14) |
| Income attributable to non-controlling interest | **21** | 17 |
| Balance at end of year | **165** | 143 |
| **Total equity** | **11,911** | 10,508 |

*See accompanying notes to the consolidated financial statements*

# NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2017 and 2016

## 1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. (OPG or the Company) was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the Province or the Shareholder). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario.

## 2. BASIS OF PRESENTATION

These consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP).

As required by *Ontario Regulation 395/11,* as amended, under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. Since January 1, 2012, OPG also has received exemptive relief from the Ontario Securities Commission (OSC) from the requirements of section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*. The exemption allows OPG to file consolidated financial statements based on US GAAP, rather than International Financial Reporting Standards (IFRS), without becoming a US Securities and Exchange Commission registrant.

The current OSC exemption, received in 2014, will terminate on the earliest of the following:

- January 1, 2019
- The financial year that commences after OPG ceases to have activities subject to rate regulation
- The effective date prescribed by the International Accounting Standards Board for the mandatory application of a standard within IFRS specific to entities with rate regulated activities.

The Company is in the process of applying for a further extension of this exemptive relief beyond January 1, 2019.

All dollar amounts are presented in Canadian dollars, unless otherwise noted. Certain 2016 comparative amounts have been reclassified from financial statements previously presented to conform to the 2017 consolidated financial statement presentation.

## 3. SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

### Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and variable interest entities (VIEs) where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS) with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle GS (Brighton Beach) with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities using the equity method.

## Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

Nuclear Waste Management Organization

In 2002, OPG and other Canadian nuclear waste producers established a separately incorporated Nuclear Waste Management Organization (NWMO) in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel in Canada. OPG has the majority of voting rights at the NWMO Board of Directors' and members' level. The NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term nuclear used fuel management plan in accordance with the NFWA. OPG provides over 90 percent of the NWMO's funding, primarily towards the design and implementation of Canada's Adaptive Phased Management plan for the long-term management of nuclear used fuel. As a result, OPG is expected to absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of intercompany transactions, are consolidated.

Fair Hydro Trust

On March 2, 2017, the Province announced Ontario's Fair Hydro Plan aimed at reducing electricity bills for all residential, farm, small businesses and other eligible consumers (Specified Consumers) in the province by refinancing a portion of the Global Adjustment over a longer period of time. The Global Adjustment includes the difference between Ontario's electricity market clearing price used to dispatch generation and the prices paid to contracted and regulated generators in the province, and the cost of conservation and demand management programs. On June 1, 2017, the *Ontario Fair Hydro Plan Act, 2017* (the Fair Hydro Act or the Act) received Royal Assent and the associated general regulation came into force in June 2017. Pursuant to the Act, effective May 1, 2017, the Independent Electricity System Operator (IESO) began to defer a portion of the Global Adjustment costs. The Act allows for the IESO to transfer a portion of the deferred balance to a financing entity that would fund the deferral in exchange for an irrevocable right to recover the balance and associated financing and other costs from Specified Consumers in the future (Investment Interest). The legislation appointed OPG as the Financial Services Manager under the Act and conveyed upon the Financial Services Manager statutory obligations, including the creation of one or more financing entities that may acquire an Investment Interest from the IESO.

In December 2017, the Fair Hydro Trust (the Trust) was established as a separate entity to be the financing entity contemplated by the Fair Hydro Act. The majority unitholder and beneficiary of the Trust is a wholly owned subsidiary of OPG. Immediately after the Trust's establishment, OPG entered into a management agreement with the Trust which provides OPG with the powers and duties of managing the Trust, including determining whether to acquire Investment Interest from the IESO, negotiating and executing all agreements, fulfilling all reporting requirements, and administering all of the Trust's day-to-day activities.

In order for the Trust to finance the acquisition of Investment Interest from the IESO, it incurs senior debt from capital markets and subordinated debt from OPG. The Trust's investment attracts financing amounts and other related fees. The Trust has minimal equity at risk to finance its activities. As part of the funding structure of the Trust, concurrent with every issuance of senior debt, it is expected that OPG will purchase subordinated debt of the Trust in an aggregate amount not to exceed 49 percent of the Trust's total outstanding debt. The subordination level may vary over time, but must be at least equal to 35 percent of the Trust's total outstanding debt. Approximately

90 percent of the amount of subordinated debt purchased by OPG is expected to be funded through equity injections in OPG by the Province, with the remainder being funded from OPG's available funds.

OPG exercises control over the key activities of the Trust. Management has concluded that OPG holds a variable interest in the Trust, of which OPG is the primary beneficiary, due to the obligation to absorb losses through ownership of the Trust's subordinated debt. Accordingly, the applicable amounts in the accounts of the Trust, after elimination of intercompany transactions, are consolidated.

PSS Generating Station LP

PSS Generating Station LP (PSS) is a limited partnership between OPG, Coral Rapids Power Corporation (CRP) and PSS Generating Station Inc. (PSS GS Inc.), a corporation owned by CRP and OPG. The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28-megawatt (MW) Peter Sutherland Sr. hydroelectric GS on the New Post Creek. OPG and PSS GS Inc. are general partners and CRP is a limited partner in the partnership. CRP is a wholly owned subsidiary of the Taykwa Tagamou Nation.

During the year ended December 31, 2017, PSS achieved commercial operations recognizing income and eliminating its deficit. Therefore, PSS has met the criteria of having sufficient equity to finance its activities and ceased being classified as a VIE. Since OPG is the primary beneficiary of PSS, it continues to consolidate PSS.

### Use of Management Estimates

The preparation of consolidated financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the end of the reporting period, and the reported amounts of revenues and expenses for the reporting periods. Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the estimate is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefit (OPEB) balances, asset retirement obligations (AROs) and associated asset retirement costs capitalized as part of property, plant and equipment (PP&E), income taxes (including deferred income taxes), contingencies, regulatory assets and regulatory liabilities, valuation of investments in segregated funds, depreciation and amortization expenses and inventories. Actual results may differ significantly from these estimates.

### Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments and classified as current assets. These securities are valued at the lower of cost and market.

### Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and net realizable value. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

### Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Asset removal costs that have not been specifically provided for in current or previous periods are charged to

operations, maintenance and administration (OM&A) expenses when incurred. Repairs and maintenance costs are expensed when incurred.

PP&E are depreciated on a straight-line basis, except for computers, which are depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2017, the amortization periods of PP&E and intangible assets are as follows:

| | |
|---|---|
| Nuclear generating stations and major components | 5 to 74 years [1] |
| Hydroelectric generating stations and major components | 10 to 100 years |
| Thermal generating stations and major components | 5 to 50 years |
| Administration and service facilities | 10 to 50 years |
| Computers – declining balance | 12% to 40% per year |
| Major application software | 5 years |
| Service equipment | 5 to 10 years |

[1] As at December 31, 2017, the end of station life for depreciation purposes for the Darlington, Pickering, Bruce A and Bruce B nuclear generating stations ranged between 2022 and 2061. Major components are depreciated over the lesser of the station life and the life of the components.

The accounting estimates related to end-of-life assumptions for PP&E and intangible assets require significant management judgment, including consideration of various operating, technological and economic factors. OPG reviews the estimated useful lives for its PP&E and intangible assets, including end-of-life assumptions for major generating assets, on a regular basis.

For nuclear generating stations operated by OPG, establishing station end-of-life assumptions primarily involves an assessment of operating lives of major life-limiting components such as fuel channel assemblies, taking into account expectations of future ability to economically operate and as appropriate refurbish the station for continued use. Expected operating lives of major life-limiting components are established through technical assessments of their fitness-for-service. Expectations of future ability to operate the station may be affected by operating licence requirements, ability to recover capital, operating and decommissioning costs, and government policy, among other factors.

Although there is a link between the age of a hydroelectric facility and the capital investment required to maintain that facility, age does not generally establish an overall upper limit on the expected useful life of a hydroelectric generating station. Regular maintenance and the replacement of specific components typically allow hydroelectric stations to operate for very long periods. An estimated useful life not exceeding 100 years is used by OPG to depreciate dams and other major hydroelectric station structures.

Station end-of-life assumptions for thermal generating stations are established based on operating life expectations of major station components and expectations of future ability to economically operate the station taking into consideration available revenue mechanisms.

### Asset Impairment

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying values of investments accounted for under the equity method are reviewed annually for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

### Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from 54 hydroelectric generating stations and the Pickering and Darlington nuclear generating stations (collectively, prescribed facilities or regulated facilities). OPG's regulated prices for these facilities are determined by the Ontario Energy Board (OEB).

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998,* the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Ontario Ministry of Energy. It regulates market participants in Ontario's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the customers. When the Company assesses that there is sufficient assurance that incurred costs in respect of the regulated facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to customers in the future in respect of the regulated facilities, including amounts related to costs that have not been incurred but for which the OEB has provided recovery through regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and regulatory liabilities recognized by the Company relate to variance and deferral accounts (regulatory accounts) authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance and deferral accounts typically capture differences between actual costs and revenues and the corresponding forecast amounts approved by the OEB in setting regulated prices, or record the impact of items not reflected in the approved regulated prices. The measurement of these regulatory assets and regulatory liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory assets and regulatory liabilities for variance and deferral account balances approved by the OEB for inclusion in regulated prices are amortized based on approved recovery or repayment periods.

Regulatory assets and regulatory liabilities for variance and deferral account balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB.

In addition to regulatory assets and regulatory liabilities for variance and deferral accounts, OPG recognizes regulatory assets and regulatory liabilities for unamortized amounts recorded in accumulated other comprehensive income (AOCI) in respect of pension and OPEB obligations, deferred income taxes, and differences between interim regulated prices charged to customers during an interim rate period and final regulated prices authorized or to be authorized by the OEB for that period, to reflect the expected recovery or repayment of these amounts through future regulated prices to be charged to customers. There are measurement uncertainties related to these balances due to the assumptions made in the determination of pension and OPEB obligations, and deferred income taxes that are attributed to rate regulated business segments, and assumptions made with respect to final regulated prices to be authorized by the OEB for the interim rate period. Regulatory assets and regulatory liabilities for differences between interim regulated prices charged to customers during an interim period rate and final regulated prices authorized or to be authorized by the OEB for that period are classified as current if they are expected to be recovered from, or

refunded to, customers within 12 months of the end of the reporting period, based on recovery or repayment periods authorized by the OEB. All other regulatory asset and regulatory liability balances are classified as non-current on the consolidated balance sheets.

The regulatory asset recognized by the Company for unamortized pension and OPEB amounts recorded in AOCI has reflected the OEB's use, since April 1, 2008, of the accrual basis of accounting for including pension and OPEB amounts in approved regulated prices for OPG. This is also the manner in which these costs are recognized in OPG's consolidated financial statements. Therefore, unamortized amounts in respect of OPG's pension and OPEB plans recognized in AOCI generally would not be reflected in regulated prices until they have been reclassified from AOCI and recognized as amortization components of the benefit costs for these plans. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit cost.

Since November 1, 2014, the OEB has limited amounts for pension and OPEB costs included in the approved revenue requirements and regulated prices to the regulated business portion of the Company's cash expenditures for its pension and OPEB plans. The difference between actual pension and OPEB costs determined using the accrual method applied in OPG's audited consolidated financial statements and OPG's actual cash expenditures for these plans is captured in the OEB-authorized Pension & OPEB Cash Versus Accrual Differential Deferral Account for future consideration by the OEB.

In 2017, the OEB issued a report outlining the guiding principles and policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the Ontario electricity and natural gas sectors. The report establishes the accrual basis of accounting as the method of determining pension and OPEB amounts for rate-setting purposes, unless the OEB finds that this method does not result in just and reasonable rates in the circumstances of a particular utility. The OEB's report and the OEB's December 28, 2017 decision on OPG's application for new regulated prices require OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account, until such time as the OEB decides on the approval and implementation of resumption of the accrual basis of recovery for OPG. The OEB's December 28, 2017 decision stated that the OEB expects OPG to file an application in 2018 comprising the disposition of the next set of variance and deferral account balances that includes OPG's proposal for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and for the method of recovery to be used for pension and OPEB amounts going forward.

It is the Company's position that the OEB's November 2014 and December 2017 decisions on OPG's applications for regulated prices and the OEB's 2017 report in this area do not constitute a change in the basis of OPG's rate recovery of pension and OPEB costs. The Company continues to believe that there is sufficient likelihood that unamortized pension and OPEB amounts that have not yet been reclassified from AOCI will be included in future regulated prices or in an OEB-authorized regulatory account for future recovery, as they are recognized in benefit costs. Therefore, the Company continues to recognize a regulatory asset for these unamortized amounts and also has recognized a regulatory asset for the balance of the Pension & OPEB Cash Versus Accrual Differential Deferral Account discussed further in Note 5.

### Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Energy revenue generated from OPG's regulated facilities is based on regulated prices determined by the OEB that include base regulated prices and, as applicable, rate riders for the recovery or repayment of approved variance and deferral account balances. The revenues from the regulated hydroelectric facilities are also subject to the OEB-approved hydroelectric incentive mechanism. This mechanism provides a pricing incentive to OPG to shift

hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers.

The base regulated prices in effect during the period January 1, 2016 to May 31, 2017 were established by the OEB's November 2014 decision and December 2014 order, using a forecast cost-of-service rate-setting methodology based on the OEB-approved revenue requirements, taking into account the OEB-approved forecasts of production and operating costs for the regulated facilities for 2014 and 2015 and a return on rate base. Rate base is a regulatory construct that, for OPG, represents the average net level of investment in regulated fixed and intangible assets in-service and an allowance for working capital. The variance and deferral account rate riders in effect during 2016 were established by the OEB in its October 2015 order on OPG's application to recover balances in most of the Company's authorized variance and deferral accounts as at December 31, 2014.

On December 28, 2017, the OEB issued its decision on OPG's May 2016 application for new regulated prices for the 2017−2021 period. The OEB set an effective date for the new regulated prices of June 1, 2017. The decision included the OEB's findings with respect to ratemaking methodologies for the prescribed facilities, the basis for inputs into the hydroelectric incentive ratemaking formula, and the elements of the nuclear revenue requirement.

Pursuant to the decision, the new base regulated prices will be determined on an incentive ratemaking methodology for the hydroelectric facilities and under a custom incentive regulation framework for the nuclear facilities. For the hydroelectric facilities, the new base regulated prices for each of the years 2017 to 2021 will be determined using a formula that annually escalates the previously approved regulated prices, subject to some adjustments, based on an industry-specific weighted inflation factor less a stretch factor adjustment. For the nuclear facilities, the new base regulated prices will be determined under a rate smoothing approach that defers a portion of the approved nuclear revenue requirement for future collection in the Rate Smoothing Deferral Account authorized by the OEB pursuant to *Ontario Regulation 53/05*, with the objective of making changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. The nuclear revenue requirement for each of the years 2017 to 2021 is based on the OEB-approved forecast of operating costs as reduced by a stretch factor amount, and a return on rate base. The difference between the non-deferred portion of the nuclear revenue requirement calculated by multiplying the nuclear base regulated price determined under rate smoothing and the OEB-approved forecast of OPG's nuclear electricity production for the year, and the total approved nuclear revenue requirement for that year determines the portion of the revenue requirement deferred for future collection in the Rate Smoothing Deferral Account. Amounts recorded in the Rate Smoothing Deferral Account are recognized as adjustments to revenue.

In January 2018, OPG submitted a draft payment amounts order to the OEB that proposed nuclear base regulated prices for each year of the 2017−2021 period based on the December 2017 decision's findings, including a rate smoothing proposal, and calculated the hydroelectric base regulated prices for 2017 and 2018 based on OEB-published inputs into the approved ratemaking formula. In the fourth quarter of 2017, OPG recorded net revenue in respect of the June 1, 2017 to December 31, 2017 interim period and a corresponding increase in net regulatory assets based on the draft payment amounts order that represents management's best estimate of the impact of the new base regulated prices and rate smoothing approach on the 2017 fiscal year.

See Note 5 for further information on the OEB's decision on OPG's May 2016 application for new regulated prices and the Rate Smoothing Deferral Account.

Revenue Recognition – Non-regulated Generation and Other Revenue

The electricity generation from OPG's non-regulated assets receives the Ontario electricity spot market price, except where an energy supply agreement (ESA) with the IESO or another contractual agreement is in place. As at December 31, 2017, most of OPG's operating non-regulated assets are subject to an ESA. Revenue from the generating stations subject to an ESA is recognized in accordance with the terms of the agreement.

OPG also sells into, and purchases from, interconnected markets of other provinces and the northeast and midwest regions of the US. All contracts that are not designated as hedges are recorded on the consolidated balance sheets at market value, with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $15 million were netted against revenue in 2017 (2016 – $19 million).

OPG derives non-energy revenue under the terms of a lease arrangement and associated agreements with Bruce Power L.P. (Bruce Power) related to the Bruce nuclear generating stations. This includes lease revenue and revenue from heavy water sales, detritiation services and waste management services. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales, real estate rentals and other service revenues. Revenues from these activities are recognized as services are provided, or as products are delivered, in accordance with the terms stipulated in the respective contracts.

**Fixed Asset Removal and Nuclear Waste Management Liabilities**

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on the plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management (Nuclear Liabilities) are increased by the present value of the incremental (variable) cost portion for the nuclear waste generated each year, with the corresponding amounts charged to OM&A expenses. Variable expenses relating to low and intermediate level radioactive waste (L&ILW) are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows, with resulting changes in the related asset retirement costs capitalized as part of the carrying amount of the related fixed assets in service. A comprehensive reassessment of all underlying assumptions and baseline cost estimates for the Nuclear Liabilities is performed periodically. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount or timing of the originally estimated undiscounted future cash flows are recorded as an adjustment to the liabilities. Upward revisions in the Nuclear Liabilities represent the present value of increases in future undiscounted cash flows determined using a current credit-adjusted risk-free rate. Downward revisions in the Nuclear Liabilities represent the present value of decreases in future undiscounted cash flows determined using the weighted average discount rate reflected in the existing liability. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the fixed asset removal and nuclear waste management liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets in service. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

### Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG has established and sets aside funds in a Used Fuel Segregated Fund and a Decommissioning Segregated Fund (together the Nuclear Segregated Funds). The Used Fuel Segregated Fund is intended to fund expenditures associated with the long-term management of radioactive used nuclear fuel bundles and certain costs of used fuel storage incurred after the nuclear stations are shut down, while the Decommissioning Segregated Fund was established to fund the costs of nuclear fixed asset removal and long-term L&ILW management, and certain costs of used fuel storage incurred after the nuclear stations are shut down. OPG's funding obligations and resulting contributions to the Nuclear Segregated Funds are determined based on periodically updated reference plans approved by the Province under the ONFA. OPG maintains the Nuclear Segregated Funds in third-party custodial and trust accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Segregated Funds and the corresponding amounts payable to/receivable from the Province are classified as held-for-trading. The Nuclear Segregated Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the real assets portfolio, using appropriate valuation techniques as outlined in Note 13, with realized and unrealized gains and losses recognized in OPG's consolidated statements of income.

### Financing Receivables

OPG's financing receivables consist of the current and irrevocable right of the Fair Hydro Trust to collect payments from Specified Consumers in the future in accordance with the Fair Hydro Act and associated general regulation. These amounts are measured at the transaction price entered into with the IESO on market terms upon acquisition and subsequently measured on an amortized cost basis. The basis of amortization follows the effective interest method.

### Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements, and if the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective, and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

All derivative contracts not designated as hedges are recorded on the consolidated balance sheets as derivative assets or liabilities at fair value, with changes in the fair value recorded in the revenue of the Services, Trading, and Other Non-Generation segment. Refer to Note 12 for a discussion of OPG's risk exposures and the derivative instruments used to manage these risks.

### Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping assets and

liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the most objective. Refer to Note 13 for a discussion of fair value measurements and the fair value hierarchy.

### Available-for-Sale Securities

Available-for-sale (AFS) securities are measured at fair value, with unrealized gains and losses due to changes in fair value recognized in other comprehensive income (OCI). Gains and losses are realized and included in net income when the securities are sold or awarded. Related transaction costs are expensed as incurred, and dividend income is included in net income in the period dividends are declared. Equity securities are initially measured at the transaction price.

### Research and Development

Research and development costs are expensed as incurred. Research and development costs incurred to discharge long-term obligations for which specific provisions have already been made, such as the Nuclear Liabilities, are charged to the related liability.

### Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset and the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statement of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is different from the actual operating lease payment, other than contingent rentals, the difference is deferred and included as assets or liabilities on the consolidated balance sheets.

### Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other postretirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post-employment benefit programs are also provided by the NWMO, which is consolidated into OPG's financial results. Unless otherwise noted, information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, demographic assumptions, experience gains or losses, salary levels, inflation, and health care cost escalation assumptions. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Discount rate, inflation rate, and changes in salary levels are three critical assumptions in the determination of benefit costs and obligations. In addition, the expected long-term rate of return on plan assets is a critical assumption in the determination of registered pension plan cost and the health care cost trend rate is a critical assumption in the determination of OPEB cost and obligations. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically

by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors giving rise to actuarial gains and losses. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods. For LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date in order to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on the pension fund's asset allocation and the expected return considering long-term risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities, corporate and government debt securities, pooled funds, real estate, infrastructure, and other investments. These assets are managed by professional investment managers. The pension fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments, and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs or credits arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the corresponding plan. Past service costs or credits arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the corridor), is amortized over the expected average remaining service life of the employees, which represents the period during which the associated economic benefits are expected to be realized by the Company. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes the funded status of its defined benefit plans on the consolidated balance sheets. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation, on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits arising during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as described above.

OPG records an offsetting regulatory asset or liability for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery or refund of these amounts through future regulated prices charged to customers. For the recoverable or refundable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset or liability for the amount of the increases or decreases in OCI and for the amounts reclassified from AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

## Income Taxes and Investment Tax Credits

OPG is exempt from income taxes under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG paying taxes similar to those imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit by the Ontario Ministry of Finance and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment. A change in the tax provision upon reassessment impacting regulated operations may be recoverable from or refundable to customers through the Income and Other Taxes Variance Account and the SR&ED ITC Variance Account authorized by the OEB.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized income tax benefits as income tax expense.

## Changes in Accounting Estimates

Useful Lives of Nuclear Long-Lived Assets

In the fourth quarter of 2017, OPG revised the accounting assumptions for the estimated useful life of the Pickering GS for the purposes of calculating depreciation. Effective December 31, 2017, the average service life of the Pickering GS was extended from an end-of-life date of December 31, 2020 for all six operating units to December 31, 2022 for Units 1 and 4 and December 31, 2024 for Units 5 to 8. The change in the useful life reflected completion of technical assessments that provided sufficient confidence in the programs and provisions in place to assure fitness-for-service of key life-limiting fuel channel components of the station, in line with the station's planned commercial operation period to 2024. This evaluation was consistent with the safety case reflected in OPG's operating licence renewal application for the Pickering GS submitted to the Canadian Nuclear Safety Commission (CNSC) in 2017. Although the current five-year operating licence for the station expires on August 31, 2018, based on the evidence and documentation submitted to the CNSC, OPG believes it is well positioned to obtain a licence renewal that would support continued commercial operation of the Pickering GS to 2024. The change to the estimated service life of the Pickering GS has been reflected in an increase to the estimate of the Nuclear Liabilities of $188 million as at

December 31, 2017, with a corresponding increase in the carrying value of the Pickering GS fixed asset balance.

The change in the Pickering GS accounting end-of-life assumptions did not impact OPG's net income in 2017. Excluding the impact of regulatory accounts, the change in the accounting end-of-life assumptions inclusive of the associated change in the Nuclear Liabilities is expected to decrease depreciation expense by approximately $77 million in 2018. Regulatory accounts, including a new deferral account proposed by OPG in an application to the OEB on December 29, 2017, are expected to offset the decrease in depreciation expense, beginning on January 1, 2018. Pending its review of this application, the OEB issued an order on January 31, 2018 establishing the proposed deferral account on an interim basis to allow OPG to begin recording amounts in the account as of January 1, 2018.

Non-Nuclear Fixed Asset Removal Liability Estimate

OPG updated the estimate of the liabilities for non-nuclear fixed asset removal as at December 31, 2017. As at December 31, 2017, OPG recognized a decrease in the non-nuclear fixed asset removal liabilities of approximately $30 million relating to thermal stations, resulting in a net decrease in asset retirement costs of $18 million capitalized as part of the carrying value of PP&E for the operating stations and a gain of $12 million recognized in net income in the fourth quarter of 2017 related to the Nanticoke and Lambton generating stations that are no longer in use and have been fully depreciated. For the operating sites, the updated estimates were based on a review of required decommissioning, clean-up and restoration activities, underlying economic assumptions, and anticipated timing of these activities in line with current accounting end-of-life assumptions. For the Nanticoke and Lambton sites, the update was based on the estimated cost of executing current decommissioning plans.

Pension and Other Post-Employment Benefits

Effective January 1, 2017, OPG changed the approach to estimate the service and interest cost components of pension and OPEB costs. OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous approach used in 2016 and prior years, these components of pension and OPEB costs were calculated using the same single equivalent discount rates as reflected in the calculation of the benefit obligations. This change in the approach was accounted for prospectively, as a change in estimate. The resulting reduction in 2017 pension and OPEB costs was approximately $135 million. Approximately 90 percent of this reduction in pension and OPEB costs was attributed to the Company's regulated business segments and therefore was offset by the impact of regulatory accounts authorized by the OEB. This change does not affect the measurement of the total benefit obligations, as the change in the current service and interest cost components from the previous approach is offset by a corresponding change in the actuarial gain or loss recorded in AOCI.

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario (FSCO) in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are outlined in Note 16. As part of the valuation, the plan's demographic and other assumptions were reviewed and revised, as necessary, by independent actuaries. Using these updated demographic assumptions and demographic data as at January 1, 2017 consistent with the new funding valuation for the registered pension plan, OPG also conducted a comprehensive actuarial valuation for accounting purposes of its pension and OPEB plans in 2017. The results of this valuation were reflected in the 2017 year-end obligations reflecting appropriate assumptions for accounting purposes as at December 31, 2017.

The discount rate used to determine the projected pension benefit obligations and the projected benefit obligations for OPEB as at December 31, 2017 was approximately 3.6 percent. This represents a decrease compared to the discount rate or approximately 3.9 percent that was used to determine the obligations as at December 31, 2016.

The deficit for the registered pension plan, for accounting purposes, increased from $2,693 million as at December 31, 2016 to $3,081 million as at December 31, 2017. This increase was largely due to a remeasurement of the liabilities at the end of 2017 reflecting lower discount rates, partially offset by the excess of actual returns on the pension plan assets over interest costs on the liabilities during the year.

The projected benefit obligations for OPEB plans increased from $2,992 million as at December 31, 2016 to $3,190 million as at December 31, 2017. This increase was largely due to a remeasurement of the liabilities at the end of 2017 reflecting a decrease in the discount rates, partially offset by the updated, lower per capita health care claims costs assumption as part of the 2017 actuarial valuation.

As at December 31, 2017, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,148 million (2016 – $3,668 million). Details of the unamortized net actuarial loss and unamortized past service costs as at December 31, 2017 and 2016 are as follows:

| *(millions of dollars)* | **Registered Pension Plans** | | **Supplementary Pension Plans** | | **Other Post-Employment Benefits** | |
|---|---|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** | **2017** | **2016** |
| Net actuarial gain not yet subject to amortization due to use of market-related values | **(418)** | (570) | **-** | - | **-** | - |
| Net actuarial loss not subject to amortization due to use of the corridor | **1,735** | 1,619 | **36** | 34 | **299** | 267 |
| Net actuarial loss subject to amortization | **2,333** | 2,238 | **80** | 72 | **79** | 3 |
| Unamortized net actuarial loss | **3,650** | 3,287 | **116** | 106 | **378** | 270 |
| Unamortized past service costs | **-** | - | **-** | - | **4** | 5 |

A change in the following assumptions, holding all other assumptions constant, would increase (decrease) pension and OPEB costs for the year ended December 31, 2017 as follows:

| *(millions of dollars)* | **Registered Pension Plans** [1] | **Supplementary Pension Plans** [1] | **Other Post-Employment Benefits** [1] |
|---|---|---|---|
| Expected long-term rate of return | | | |
| 0.25% increase | (32) | n/a | n/a |
| 0.25% decrease | 32 | n/a | n/a |
| Discount rate | | | |
| 0.25% increase | (56) | (1) | (2) |
| 0.25% decrease | 59 | 1 | 13 |
| Inflation [2] | | | |
| 0.25% increase | 98 | 1 | - |
| 0.25% decrease | (91) | (1) | - |
| Salary increases | | | |
| 0.25% increase | 22 | 3 | - |
| 0.25% decrease | (20) | (2) | - |
| Health care cost trend rate | | | |
| 1% increase | n/a | n/a | 77 |
| 1% decrease | n/a | n/a | (29) |

n/a – change in assumption not applicable.

[1] Excludes the impact of regulatory accounts.

[2] With a corresponding change in the salary increase assumption

## Recent Accounting Pronouncements Not Yet Adopted

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, *Revenue from Contracts with Customers* (Topic 606), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance, under US GAAP. The core principle of Topic 606 is to recognize revenues when promised goods or services are transferred to customers in an amount that reflects the consideration to which an entity expects to be entitled for those goods or services. Either a full retrospective application or a modified retrospective application is required for annual periods beginning on or after January 1, 2018, including interim periods within that year. Early adoption is permitted.

OPG has assessed the impact of the standard on accounting for the Company's revenue streams and consolidated financial statements. OPG's major revenue streams include generation revenue from regulated prices established by the OEB and revenue from generation assets under long-term contractual arrangements with the IESO. OPG has substantially completed its analyses of the impact of Topic 606 on all of its revenue streams, and has not identified any material differences in the timing or amount of revenue recognition.

The Company will apply the new revenue standard in its 2018 first quarter interim financial statements and is in the process of evaluating the additional disclosures required under the new standard.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overall: Recognition and Measurement of Financial Assets and Financial Liabilities*. Under the updated guidance, entities will have to measure equity investments at fair value and recognize any changes in fair value in net income. The update will be effective for OPG's 2018 fiscal year, including interim periods. As a result of this update, effective January 1, 2018, the AFS classification for securities will no longer be available, with any unrealized gains and losses related to such securities recognized in net income instead of OCI. Any unrealized gains and losses for AFS securities reported by OPG in AOCI as of the end of 2017 will be reclassified to retained earnings as of January 1, 2018. As at December 31, 2017, a cumulative loss of $9 million on OPG's AFS securities was recorded in AOCI, and will be reclassified to opening retained earnings effective January 1, 2018. There are no other significant differences to OPG's consolidated financial statements upon adoption of the new standard.

Lease Accounting

In February 2016, the FASB issued ASU No. 2016-02, *Leases* (Topic 842) to replace existing lease accounting guidance under Topic 840. The update includes comprehensive changes to existing guidance, particularly for lessees, and aims to increase transparency and comparability among organizations by requiring the recognition of lease assets and lease liabilities on the balance sheet. The standard is effective for annual periods beginning after December 15, 2018, including interim periods within that year.

Under the current guidance related to the new leasing standard, entities are required to use a modified retrospective approach for leases that exist, or are entered into, after the beginning of the earliest comparative period presented in the financial statements of the period of adoption. Under this method, Topic 842 would effectively be implemented by recognizing any adjustments stemming from the transition as of the beginning of the earliest comparative period presented in the entity's financial statements. Full retrospective application is prohibited. In January 2018, the FASB issued a proposed ASU (ASU 2018-200) wherein entities would be able to utilize an additional optional transition method of recording the cumulative impact of adopting the new lease standard as an adjustment to opening balances in the initial period of adoption, with comparative periods continuing to be presented in accordance with Topic 840, including disclosures. The Company will continue to monitor the status of this proposed ASU.

The FASB also issued ASU No. 2018-01, *Land Easement Practical Expedient for Transition to Topic 842* in January 2018. The amendments therein allow an entity to choose not to evaluate under Topic 842 land easements that exist or expired before the entity's adoption of the new leasing standard and that were not previously accounted for as leases under Topic 840.

The Company continues to implement and execute a comprehensive project governance framework, which comprises a Steering Committee, Implementation & Stakeholder Committee, Project Management Office, and various working groups in order to evaluate and implement the new standard. The working groups are represented by cross functional finance and non-finance stakeholders and will support the financial and operational implementation of the standard. The Company continues to evaluate the impact of the new leasing standard on its consolidated financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU No. 2017-07, *Compensation – Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost*. Under the new guidance, employers that sponsor defined benefit plans for pensions and/or other postretirement benefits are required to present the service cost component of net periodic benefit cost in the same statement of income line item as other employee compensation costs arising from services rendered during the period. The other components of the net periodic benefit cost are to be presented separately from the line item that includes the service cost and outside of any subtotal of income from operations, if such a subtotal is presented. In addition, the new guidance requires that only the service cost component of net benefit cost be eligible for capitalization.

This guidance is effective for fiscal years beginning after December 15, 2017, including interim periods of those years. The guidance will not have a material impact on OPG's consolidated financial statements, as OPG currently capitalizes only the service cost component of postretirement benefits costs. Additionally, OPG already includes the service cost component of postretirement benefit costs with other compensation costs, within the OM&A expenses line item in the consolidated statements of income, and does not show a subtotal of income from operations. As such, the new guidance will not affect the presentation of OPG's consolidated financial statements.

## 4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

PP&E as at December 31 consist of the following:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Nuclear generating stations | **11,985** | 11,057 |
| Regulated hydroelectric generating stations | **9,566** | 9,430 |
| Contracted generation portfolio generating stations | **3,935** | 3,751 |
| Other property, plant and equipment | **372** | 1,595 |
| Construction in progress | **4,092** | 3,482 |
| | **29,950** | 29,315 |
| Less: accumulated depreciation | | |
| Generating stations | **8,480** | 7,948 |
| Other property, plant and equipment | **148** | 1,369 |
| | **8,628** | 9,317 |
| | **21,322** | 19,998 |

Construction in progress as at December 31 consists of the following:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Darlington Refurbishment | **3,507** | 2,563 |
| Peter Sutherland Sr. GS | **17** | 236 |
| Other | **568** | 683 |
| | **4,092** | 3,482 |

Interest capitalized to construction in progress during 2017 was $162 million (2016 – $141 million), at an average rate of five percent (2016 – five percent).

Intangible assets as at December 31 consist of the following:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Nuclear generating stations | **122** | 122 |
| Regulated hydroelectric generating stations | **6** | 7 |
| Contracted generation portfolio generating stations | **5** | 4 |
| Computer software and other intangible assets | **393** | 350 |
| Development in progress | **39** | 20 |
| | **565** | 503 |
| Less: accumulated amortization | | |
| Generating stations | **123** | 120 |
| Computer software and other intangible assets | **309** | 284 |
| | **432** | 404 |
| | **133** | 99 |

Depreciation and amortization expenses, including amounts recognized in regulatory variance and deferral accounts authorized by the OEB, for the years ended December 31 consist of the following:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Depreciation | **649** | 602 |
| Amortization of intangible assets | **30** | 27 |
| Amounts recognized in regulatory variance and deferral accounts | **-** | 26 |
| Amortization of regulatory assets and liabilities *(Note 5)* | **-** | 602 |
| | **679** | 1,257 |

Shareholder Declarations and Shareholder Resolutions to Sell Certain Non-Core Real Estate Properties

In December 2015, OPG received a Shareholder Declaration and a Shareholder Resolution requiring the Company to sell its head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street in Toronto, Ontario. The sale was completed in April 2017 with a gain on sale of $283 million, which is net of tax effects of $95 million, recognized in net income during the year ended December 31, 2017. The pre-tax gain on sale was recorded as an item of Other gains in the consolidated statement of income in the Services, Trading, and Other Non-Generation segment. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. The amount of designated proceeds to be transferred into the Consolidated Revenue Fund is expected to approximate the after-tax gain on sale. The transfer is expected to take place as early as in the first quarter of 2018, following a special dividend authorized by OPG's Board of Directors in March 2018.

In June 2016, OPG received a Shareholder Declaration and a Shareholder Resolution that requires the Company to sell its former Lakeview GS site located in Mississauga, Ontario. OPG has entered into a purchase and sale agreement with a purchaser, with the sale scheduled to close in March 2018. Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from this disposition, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. In accordance with the Shareholder Resolution, approximately one-third of the site is to be transferred to the City of Mississauga, by the purchaser, for parkland, institutional, and cultural uses. The Lakeview GS site assets were fully depreciated prior to initiating an active program to locate a buyer.

## 5. REGULATORY ASSETS AND LIABILITIES

Through its March 2017 approval of a partial settlement agreement reached by OPG and intervenors on a limited set of issues in OPG's May 2016 application for new regulated prices for the 2017−2021 period (Settlement Agreement) and its December 2017 decision on the application, the OEB approved OPG's request to recover amounts totalling $305 million related to previously recorded variance and deferral account balances, without adjustments. These approved amounts relate to the December 31, 2015 balances in all of the Company's OEB-authorized regulatory accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account, less amounts previously approved for recovery or repayment for these accounts in 2016. In its draft payment amounts order submitted to the OEB in January 2018, OPG proposed that the approved regulatory account amounts be recovered over a three-year period of 2019 to 2021. The final recovery period will be determined by the OEB through the payment amounts order process. During 2017, OPG did not recover or repay any variance and deferral account balances and did not record any amortization related to regulatory assets and regulatory liabilities for these accounts.

During 2016, OPG recorded amortization of regulatory assets and liabilities for the variance and deferral account balances approved for disposition by the OEB's October 2015 order, on a straight-line basis, based on recovery or repayment periods authorized by that order.

The OEB's approval of the Settlement Agreement provided for the continuation of all applicable previously existing variance and deferral accounts effective June 1, 2017. Consistent with the effective date of the OEB's December 2017 decision, for the period from January 1, 2016 to May 31, 2017, OPG recognized regulatory assets and regulatory liabilities for additions recorded in these accounts pursuant to the OEB's previous decisions and orders, relative to amounts reflected in the cost-of-service regulated prices in effect prior to June 1, 2017. For the period from June 1, 2017 to December 31, 2017, OPG recognized regulatory assets and regulatory liabilities for additions recorded in these accounts consistent with the OEB's December 2017 decision and OPG's January 2018 draft payment amounts order submission.

Where authorized by the OEB, OPG recorded interest on unamortized balances in the variance and deferral accounts at the OEB-prescribed interest rate of 1.10 percent per annum during the period from January 1, 2016 to September 30, 2017 and 1.50 percent per annum during the fourth quarter of 2017.

The regulatory assets and liabilities recorded as at December 31 are as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Regulatory assets | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Pension and OPEB Cost Variance Account | **716** | 716 |
| Pension & OPEB Cash Versus Accrual Differential Deferral Account | **614** | 497 |
| Hydroelectric Surplus Baseload Generation Variance Account | **360** | 210 |
| Bruce Lease Net Revenues Variance Account | **121** | 95 |
| Other variance and deferral accounts | **124** | 107 |
| | **1,935** | 1,625 |
| Interim Period Revenue Shortfall | **544** | - |
| Pension and OPEB Regulatory Asset *(Note 11)* | **3,855** | 3,392 |
| Deferred Income Taxes | **897** | 838 |
| Total regulatory assets | **7,231** | 5,855 |
| Regulatory liabilities | | |
| *Variance and deferral accounts authorized by the OEB* | | |
| Hydroelectric Water Conditions Variance Account | **150** | 51 |
| Pension & OPEB Cash Payment Variance Account | **140** | 58 |
| Changes in Station End-of-Life Dates Deferral Account | **103** | 71 |
| Other variance and deferral accounts | **201** | 130 |
| Total regulatory liabilities | **594** | 310 |

The changes in the regulatory assets and liabilities during 2017 and 2016 are as follows:

| *(millions of dollars)* | Pension and OPEB Cost Variance | Pension & OPEB Cash vs Accrual Differential Deferral | Hydro-electric Surplus Baseload Generation Variance | Bruce Lease Net Revenues Variance | Hydro-electric Water Conditions Variance | Pension & OPEB Cash Variance | Changes in Station End-of-Life Dates Deferral | Other Variance and Deferral (net) | Interim Period Revenue Shortfall | Pension and OPEB Regulatory Asset | Deferred Income Taxes |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Net regulatory assets (liabilities) January 1, 2016 | 865 | 315 | 114 | 95 | (23) | 28 | - | 260 | - | 3,362 | 792 |
| Increase (decrease) | - | 182 | 126 | 143 | (33) | (86) | (71) | - | - | 30 | 46 |
| Interest | - | - | 2 | - | (1) | - | - | 1 | - | - | - |
| Amortization | (149) | - | (32) | (143) | 6 | - | - | (284) | - | - | - |
| Net regulatory assets (liabilities) December 31, 2016 | 716 | 497 | 210 | 95 | (51) | (58) | (71) | (23) | - | 3,392 | 838 |
| Increase (decrease) | **-** | **117** | **146** | **25** | **(98)** | **(81)** | **(32)** | **(52)** | **544** | **463** | **59** |
| Interest | **-** | **-** | **4** | **1** | **(1)** | **(1)** | **-** | **(2)** | **-** | **-** | **-** |
| Net regulatory assets (liabilities) December 31, 2017 | **716** | **614** | **360** | **121** | **(150)** | **(140)** | **(103)** | **(77)** | **544** | **3,855** | **897** |

## Pension and OPEB Cost Variance Account

As authorized by the OEB, for the period from March 1, 2011 to October 30, 2014, the Pension and OPEB Cost Variance Account recorded the differences between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis and related tax impacts, and corresponding forecast amounts reflected in the regulated prices then in effect. In its November 2014 and December 2017 decisions, the OEB determined that the pension and OPEB amounts reflected in OPG's regulated prices established by these decisions effective November 1, 2014 and June 1, 2017, respectively, would be limited to the Company's estimated minimum contributions to its registered pension plan and a forecast of OPG's expenditures on the OPEB and supplementary pension plans for the regulated business. As such, the OEB has ordered the Pension and OPEB Cost Variance Account to record only amortization since November 1, 2014, as applicable.

In its October 2015 order, the OEB approved the continuation of the previously authorized recovery of 10/12 of the account balance as at December 31, 2012 over a 144-month period to December 31, 2024. Amounts recorded in the account in 2013 and 2014 were approved for recovery over a 72-month period commencing July 1, 2015 by the OEB's October 2015 order. Consistent with the October 2015 order, regulatory amounts to be recovered pursuant to the OEB's 2017 decisions included one-sixth of the previously approved 10/12 portion of the Pension and OPEB Cost Variance Account balance as at December 31, 2012 and one-third of the previously approved amounts recorded in the account in 2013 and 2014.

## Pension & OPEB Cash Versus Accrual Differential Deferral Account

The Pension & OPEB Cash Versus Accrual Differential Deferral Account was originally established by the OEB's November 2014 decision and December 2014 order and was continued by the OEB's 2017 decisions. Effective November 1, 2014, this deferral account records the difference between OPG's actual pension and OPEB costs for the regulated business determined on an accrual basis under US GAAP and OPG's corresponding actual cash

expenditures for these plans. The balance in the account as at December 31, 2017 represents the excess of costs calculated using the accrual basis over the cash basis for the period from November 1, 2014 to December 31, 2017. As discussed in Note 3, the Company has recognized the amount set aside in the deferral account as a regulatory asset. The OEB's December 2017 decision stated that the OEB expects OPG to file an application in the 2018 calendar year comprising the disposition of the next set of variance and deferral account balances that includes OPG's proposal for the Pension & OPEB Cash Versus Accrual Differential Deferral Account and for the method of recovery of pension and OPEB amounts to be used going forward.

In accordance with US GAAP requirements, OPG recognizes a regulatory asset for the OPEB portion of deferred costs recorded in the Pension & OPEB Cash Versus Accrual Differential Deferral Account to the extent that the recovery of these costs commences within five years and is completed in full within 20 years of the period in which the costs were incurred, provided that the pattern of recovery within these constraints does not result in rate increases for a future year that is higher than the previous year.

### Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric Surplus Baseload Generation Variance Account records the impact of forgone production at OPG's regulated hydroelectric facilities due to surplus baseload generation conditions.

Variance and deferral account balances approved for disposition by the OEB's 2017 decisions included amounts recorded in this variance account during 2015.

### Bruce Lease Net Revenues Variance Account

In accordance with *Ontario Regulation 53/05*, the OEB is required to include the difference between OPG's revenues and costs associated with the two nuclear generating stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. Based on *Ontario Regulation 53/05* requirements, the OEB has established a variance account that captures differences between OPG's actual revenues and costs related to these stations and the corresponding forecasts included in approved nuclear regulated prices, including the costs associated with OPG's Nuclear Liabilities and the earnings from the portion of the Nuclear Segregated Funds related to the Bruce stations.

The OEB had previously ordered the portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability then embedded in the terms of the lease agreement between OPG and Bruce Power related to the Bruce nuclear generating stations (Bruce Lease) to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power and associated income tax impacts. The OEB's October 2015 order authorized amounts to be recovered from customers for the derivative liability on this basis, over the period to the end of 2016. In December 2015, as a result of amendments to the Bruce Lease, OPG reversed the derivative liability, with a corresponding reduction to the regulatory asset for the Bruce Lease Net Revenues Variance Account. Amounts collected from customers for the derivative liability for periods after its reversal are subject to refund in the future and have been recognized as a regulatory liability as part of the variance account balance.

The regulatory asset balance for the Bruce Lease Net Revenues Variance Account as at December 31, 2017 reflects a net amount of $190 million recoverable from customers for non-derivative variances recorded in 2015 through 2017, which is partially offset by a liability of $69 million to customers for amounts recovered for the derivative liability since its reversal in December 2015. Non-derivative amounts recorded during 2016 and 2017 included those arising from the adjustment to the Nuclear Liabilities and related changes to the estimated service lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015 and the adjustment to the Nuclear Liabilities effective December 31, 2016 resulting from the ONFA reference plan update process.

Variance and deferral account balances approved for disposition by the OEB's 2017 decisions included non-derivative amounts recorded in the Bruce Lease Net Revenues Variance Account during 2015 as well as amounts refundable to customers in respect of the derivative liability.

### Interim Period Revenue Shortfall

The Interim Period Revenue Shortfall regulatory asset as at December 31, 2017 reflects an estimate of the revenue shortfall arising from the difference between previously approved regulated prices that continued to be charged to customers for OPG's nuclear and regulated hydroelectric generation for the June 1, 2017 to December 31, 2017 interim period and new regulated prices to be authorized by the OEB for that period as part of the final payment amounts order process. OPG recognized the Interim Period Revenue Shortfall regulatory asset and a corresponding increase to revenue in the fourth quarter of 2017 to reflect management's best estimate of new regulated prices based on the OEB's December 2017 decision, being the regulated prices proposed by OPG in its January 2018 submission of the draft payment amounts order to the OEB.

The December 2017 decision determined that OPG will recover the interim period revenue shortfall for the period between June 1, 2017 and the implementation date of the new regulated prices through prospective rate riders, over a period to be determined as part of the payment amounts order process. OPG's draft payment amounts order proposed a three-year recovery period of 2019 to 2021 for the revenue shortfall.

### Pension and OPEB Regulatory Asset

The Pension and OPEB Regulatory Asset represents unamortized amounts in respect of OPG's pension and OPEB plans that have been recognized in OCI and not yet reclassified into the amortization component of the benefit costs in respect of these plans. These amounts are expected to be recovered from customers through future regulated prices. The regulatory asset is reversed as underlying unamortized balances are amortized as components of benefit costs. For further details, refer to Note 3 under the heading, *Rate Regulated Accounting*. The AOCI amounts related to pension and OPEB plans are presented in Note 11.

### Deferred Income Taxes

OPG is required to record a regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities. In addition, OPG is required to recognize a deferred income tax liability or asset for the regulatory asset or regulatory liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to customers. Income taxes are discussed in Note 9.

### Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the production forecast approved by the OEB in setting regulated hydroelectric prices, and the actual water conditions.

Variance and deferral account balances approved for disposition by the OEB's 2017 decision included amounts recorded in this variance account during 2015.

### Pension & OPEB Cash Payment Variance Account

The Pension & OPEB Payment Variance Account was originally established by the OEB's November 2014 decision and December 2014 order and was continued by the OEB's 2017 decisions. The account records the difference between OPG's actual contributions to its registered pension plan and expenditures on its OPEB and supplementary pension plan plans for the regulated business, and such forecast amounts reflected in the regulated prices.

Variance and deferral account balances approved for disposition by the OEB's 2017 decisions included the balance in this variance account as of December 31, 2015.

### Changes in Station End-of-Life Dates Deferral Account

The Changes in Station End-of-Life Dates Deferral Account was established by the OEB effective January 1, 2016 in response to an application by OPG for an accounting order to establish a new deferral account to record the revenue requirement impact on the Pickering and Darlington nuclear generating stations of changes to the Nuclear Liabilities and depreciation expense arising from extensions in the estimated useful lives of OPG's nuclear stations, for accounting purposes, effective December 31, 2015. These impacts were not reflected in the regulated prices in effect prior to June 1, 2017. The deferral account recorded these impacts until the effective date for new regulated prices of June 1, 2017 established by the OEB's December 2017 decision. The new regulated prices will reflect the impacts of the above changes in Nuclear Liabilities and depreciation expense.

### Nuclear Liability Deferral Account

Pursuant to *Ontario Regulation 53/05*, the OEB has authorized the Nuclear Liability Deferral Account in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA. Effective January 1, 2017, the Province approved the 2017−2021 ONFA reference plan (2017 ONFA Reference Plan). As the regulated prices in effect prior to June 1, 2017 did not reflect the impact of the 2017 ONFA Reference Plan, OPG recorded an increase in the regulatory asset for the Nuclear Liability Deferral Account during the period from January 1, 2017 to May 31, 2017. The new regulated prices effective June 1, 2017 will reflect the impact of the 2017 ONFA Reference Plan.

Components of the increase in the regulatory asset for the deferral account recorded during the years ended December 31, with reductions (increases) to corresponding expenses, are summarized as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Fuel expense | **(1)** | - |
| Low and intermediate level waste management variable expenses [1] | **2** | 2 |
| Depreciation expense | **10** | - |
| Return on rate base [2] | **(6)** | - |
| Income taxes | **11** | - |
| | **16** | 2 |

[1] Amount was recorded as a reduction to OM&A expenses.

[2] Amount was recorded as an increase to accretion on fixed asset removal and nuclear waste management liabilities.

### Rate Smoothing Deferral Account

The Rate Smoothing Deferral Account was established by the OEB's December 2017 decision pursuant *to Ontario Regulation 53/05*. The deferral account records, for future recovery, a portion of the annual OEB-approved revenue requirements for OPG's nuclear facilities during the period from January 1, 2017 to the end of the Darlington Refurbishment project. *Ontario Regulation 53/05* requires the deferred portion of nuclear revenue requirement to be determined in a manner that makes changes in OPG's production-weighted average nuclear and hydroelectric regulated price more stable year over year. Per the regulation, the Rate Smoothing Deferral Account records interest at a long-term debt rate reflecting OPG's cost of long-term borrowing approved by the OEB, compounded annually. The regulation requires the OEB to authorize recovery of the balance in the account on a straight-line basis over a period not to exceed ten years following the end of the Darlington Refurbishment project.

*Ontario Regulation 53/05* requires the OEB to determine the revenue requirements for OPG's nuclear facilities on a five-year basis for the ten-year period beginning on January 1, 2017. The portion of the approved revenue

requirement recorded in the Rate Smoothing Deferral Account each year is to be determined by the OEB on a five-year basis during this ten-year period.

OPG recognizes positive amounts deferred under rate smoothing and recorded in the Rate Smoothing Deferral Account as an increase in the regulatory asset for the deferral account and an increase in revenue in the period to which the underlying approved revenue requirement relates. Negative amounts determined under rate smoothing and recorded in the Rate Smoothing Deferral Account are correspondingly recorded as a regulatory liability for the deferral account and a decrease to revenue.

OPG recorded a regulatory liability of $63 million for the Rate Smoothing Deferral Account in the fourth quarter of 2017. Inclusive of interest payable of $1 million, this amount reflects management's best estimate of the impact of rate smoothing for 2017. The estimate reflects OPG's rate smoothing proposal submitted to the OEB in January 2018 as part of the draft payment amounts order. OPG's proposal was developed in accordance with *Ontario Regulation 53/05* and the OEB's direction in the December 2017 decision.

### Other Variance and Deferral Accounts

*Regulatory assets*

As at December 31, 2017 and 2016, regulatory assets for Other variance and deferral accounts included amounts for the Nuclear Liability Deferral Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, the Nuclear Development Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account. As at December 31, 2017, these regulatory assets also included the Fitness for Duty Deferral Account.

The Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account record any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast nuclear and regulated hydroelectric production, respectively.

The Nuclear Development Variance Account records variances between the actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the corresponding forecasts reflected in the regulated prices approved by the OEB.

The Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account was established pursuant to the OEB's January 2016 decision on OPG's motion that requested the OEB to review and vary parts of its November 2014 decision, including the disallowed Niagara Tunnel project capital costs. The variance account captures the revenue requirement impact of the portion of the original disallowance reversed by the OEB's January 2016 decision.

The Fitness for Duty Deferral Account was established by the OEB's December 2017 decision, effective June 1, 2017. The account records OPG's costs related to implementing the CNSC's new fitness for duty requirements.

*Regulatory liabilities*

As at December 31, 2017 and 2016, regulatory liabilities for Other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Income and Other Taxes Variance Account, the Hydroelectric Incentive Mechanism Variance Account, and the Capacity Refurbishment Variance Account. As at December 31, 2017, these regulatory liabilities also included the Rate Smoothing Deferral Account and the SR&ED ITC Variance Account.

The Ancillary Services Net Revenue Variance Account has been authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Income and Other Taxes Variance Account includes deviations in income taxes for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates and rules, as well as reassessments.

The Hydroelectric Incentive Mechanism Variance Account records a credit to customers equal to 50 percent of OPG's hydroelectric incentive mechanism revenues above a specified threshold for the regulated hydroelectric facilities.

Pursuant to *Ontario Regulation 53/05*, the Capacity Refurbishment Variance Account captures variances from the forecasts reflected in the regulated prices for capital and non-capital costs incurred to increase the output of, refurbish, or add operating capacity to one or more of the regulated facilities. The balance in the account as at December 31, 2017 includes cost variances related to the refurbishment of the Darlington GS, life extension initiatives at the Pickering GS, and other projects.

The SR&ED ITC Variance Account was established by the OEB's December 2017 decision, effective June 1, 2017. The account records the income tax expense impact for the nuclear facilities as a result of differences between actual Scientific Research & Experimental Development investment tax credits earned by OPG and such forecast amounts reflected in the regulated prices.

Variance and deferral account balances approved for disposition by the OEB's 2017 decisions included amounts recorded in the applicable Other variance and deferral accounts during 2015.

## 6. LONG-TERM DEBT AND NET INTEREST EXPENSE

Long-term debt consists of the following as at December 31: [1]

| *(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| Notes payable to the OEFC [2] | | |
| Senior Notes | | |
| bear interest at rates ranging from 3.12% to 5.44%; maturity dates ranging from 2018 to 2047 | **3,195** | 3,295 |
| Medium Term Note Program [2] | | |
| Senior Notes | | |
| 3.32% due 2027 | **500** | - |
| UMH Energy Partnership [3] | | |
| Senior Notes | | |
| 7.86% due 2041 | **181** | 184 |
| PSS Generating Station Limited Partnership [4] | | |
| Senior Notes | | |
| 4.90% due 2067 | **245** | 245 |
| Lower Mattagami Energy Limited Partnership [5] | | |
| Senior Notes | | |
| bear interest at rates ranging from 2.40% to 5.26%; maturity dates ranging from 2021 to 2052 | **1,595** | 1,795 |
| Fair Hydro Trust [6] | | |
| Senior Notes | | |
| 2.32% due 2019 | **601** | - |
| Other | **19** | 15 |
| | **6,336** | 5,534 |
| Less: bond issuance fees | **(17)** | (14) |
| Less: due within one year | **(398)** | (1,103) |
| Long-term debt | **5,921** | 4,417 |

[1] The interest rates disclosed reflect the effective interest rate of the debt, except for the Fair Hydro Trust senior notes, which reflect the weighted average interest rate during the period the notes were outstanding from December 21, 2017 to December 31, 2017.

[2] These notes are direct unsecured obligations of OPG and rank *pari passu* with all other OPG's unsubordinated and unsecured obligations.

[3] These notes are secured by the assets of the Upper Mattagami and Hound Chute project. Principal repayments of $3 million per year are made on a semi-annual basis until maturity in 2041, at which time the remaining principal balance of $116 million becomes due.

[4] These notes are secured by the assets of the Peter Sutherland Sr. GS project, and are recourse to OPG until the recourse release date. These notes rank *pari passu* to the senior notes from the OEFC and Medium Term Note program. The notes have an interest-only feature until 2025 and will be amortized with blended semi-annual principal and interest payments thereafter until maturity in 2067, at which time the remaining principal balance of $49 million becomes due.

[5] These notes are secured by the assets of the Lower Mattagami River project, including existing and new operating facilities.

[6] The notes were issued under an $800 million two-year revolving warehouse facility and are secured by the assets of the Fair Hydro Trust.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, with an expiry date of December 31, 2017. During 2017, the agreement was amended, with the credit facility increased to $2,350 million and the expiry date extended to December 31, 2018. As of December 31, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017,

OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity in October 2027. The offering was made under OPG's $2 billion short form base shelf prospectus filed in September 2017.

In 2015, PSS issued long-term debt totalling $245 million in support of the Peter Sutherland Sr. GS project. The majority of the debt proceeds, totalling $180 million, were invested in a structured deposit note with staggered maturity dates ranging from January 2016 to April 2017. As at December 31, 2017, the deposit note had matured.

In December 2017, the Fair Hydro Trust entered into an $800 million revolving warehouse facility agreement with an expiry date of December 2019. As at December 31, 2017, there were outstanding senior notes of $601 million under this facility, which were used to finance 51 percent of the Trust's funding requirement for the acquisition of the first tranche of Investment Interest from the IESO in December 2017. The outstanding balance of the revolving warehouse credit facility has been classified as long-term debt as at December 31, 2017 reflecting the contractual terms of the facility agreement. Interest incurred on this debt is recorded within earnings from Fair Hydro Trust in the consolidated statements of income.

In February 2018, the Fair Hydro Trust issued $500 million of senior notes payable with a coupon interest rate of 3.36 percent and an effective interest rate of 3.44 percent, payable semi-annually until maturity on May 15, 2033. The proceeds were used to repay the majority of the outstanding balance of the revolving warehouse facility issued by the Trust in December 2017.

The following table summarizes the net interest expense for the years ended December 31:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Interest on long-term debt [1] | **289** | 290 |
| Interest on short-term debt | **7** | 8 |
| Interest income | **(9)** | (7) |
| Interest capitalized to property, plant and equipment and intangible assets | **(162)** | (141) |
| Interest related to regulatory assets and liabilities [2] | **(30)** | (30) |
| Net interest expense | **95** | 120 |

[1] Excludes interest on Fair Hydro Trust senior debt.

[2] Includes interest to recognize the cost of financing related to regulatory accounts, as authorized by the OEB, and interest deferred in the Bruce Lease Net Revenues Variance Account, the Capacity Refurbishment Variance Account, and the Niagara Tunnel Project Pre-December 2008 Disallowance Variance Account.

Interest paid in 2017 was $258 million (2016 – $269 million), of which $251 million (2016 – $261 million) relates to interest paid on long-term debt.

The total net book value of the pledged assets of PSS, UMH Energy Partnership, Lower Mattagami Energy Limited Partnership (LME), and Lower Mattagami Limited Partnership against their debt as at December 31, 2017 was $3,645 million (2016 – $3,510 million).

The total net book value of the secured assets of the Fair Hydro Trust pledged in favour of specified creditors of the Trust, including the senior debtholders and OPG in its capacity as subordinated debtholder and Financial Services Manager of the Trust, was $1,190 million as at December 31, 2017.

## 7. SHORT-TERM DEBT

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During 2017, OPG renewed and extended the expiry date of both tranches to May 2022. There were no amounts outstanding under the bank credit facility. There was $100 million of commercial paper outstanding under OPG's commercial paper program as at December 31, 2017. The commercial paper program is used to provide short-term funding for the Company, at interest rates of approximately one percent and for less than one year in duration.

As at December 31, 2017, LME maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program. The facility consists of a $300 million tranche maturing in August 2022 and a $100 million tranche maturing in August 2018. As at December 31, 2017, there was $160 million of commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at December 31, 2017 under the first tranche of LME's credit facility.

As at December 31, 2017, OPG maintained $25 million of short-term, uncommitted overdraft facilities and $468 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at December 31, 2017, a total of $390 million of Letters of Credit had been issued under these facilities. This included $353 million for the supplementary pension plans, $36 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company's short-term, uncommitted credit facilities include an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million, expiring on November 30, 2018. As at December 31, 2017, there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

UMH Energy Partnership has entered into an $8 million short-term, uncommitted overdraft facility and $16 million of irrevocable, standby Letters of Credit facilities in support of its operations. As at December 31, 2017, total Letters of Credit of $15 million had been issued under these facilities.

## 8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUNDS AND FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

The liabilities for fixed asset removal and nuclear waste management on a present value basis as at December 31, consist of the following:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Liability for nuclear used fuel management | **11,970** | 11,292 |
| Liability for nuclear decommissioning and nuclear low and intermediate level waste management | **8,107** | 7,811 |
| Liability for non-nuclear fixed asset removal | **344** | 381 |
| Fixed asset removal and nuclear waste management liabilities | **20,421** | 19,484 |

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Liabilities, beginning of year | **19,484** | 20,169 |
| Increase in liabilities due to accretion [1] | **974** | 1,024 |
| Decrease in liabilities resulting from the ONFA reference plan update | **-** | (1,567) |
| Increase in liabilities reflecting changes to the estimated useful lives of nuclear generating stations *(Note 3)* | **188** | - |
| Decrease in liabilities reflecting changes in the estimate of liabilities for thermal generating stations *(Note 3)* | **(30)** | - |
| Increase in liabilities due to nuclear used fuel and nuclear expenses and other expenses [1] | **118** | 133 |
| Liabilities settled by expenditures on fixed asset removal and nuclear waste management during the year | **(313)** | (275) |
| Liabilities, end of year | **20,421** | 19,484 |

[1] Amounts shown exclude the impact of regulatory variance and deferral accounts.

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage and safe storage of the nuclear stations, dismantlement, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs are long-term in nature. The most recent comprehensive update of the cost estimates for the Nuclear Liabilities is contained in the 2017−2021 ONFA reference plan, which was finalized and approved by the Province in the fourth quarter of 2016 (2017 ONFA Reference Plan). The update resulted in a decrease of approximately $1,570 million in the Nuclear Liabilities as at December 31, 2016.

As discussed in Note 3, OPG recognized an increase in the Nuclear Liabilities of $188 million as at December 31, 2017 to reflect the changes in the estimated useful life of the Pickering GS. The increase in the liabilities was determined by discounting the net incremental future cash flows at 2.94 percent.

For the purposes of calculating OPG's Nuclear Liabilities, as at December 31, 2017, consistent with the current accounting end-of-life assumptions, nuclear station decommissioning activities are projected to occur over approximately the next 80 years. The estimates for the Nuclear Liabilities include cash flow estimates for decommissioning the nuclear stations for approximately 40 years after stations are shut down and to 2088 for placement of used fuel into the assumed long-term disposal repository, followed by extended monitoring.

The significant assumptions underlying operational, technical, and economic factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the nuclear waste programs including construction of waste disposal facilities, station end-of-life dates, waste disposal methods, financial indicators, or the technology employed, may result in significant changes to the value of the liabilities. With programs of this long-term duration and the evolving technology to handle the nuclear waste, there is a significant degree of inherent uncertainty surrounding the measurement of the costs for these programs. These costs may increase or decrease over time.

### Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, required that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs as specified in the NFWA. This organization, the NWMO, is responsible for the design and implementation of Canada's plan for the long-term management of nuclear used fuel waste. To estimate its liability for nuclear used fuel management costs, OPG has adopted an approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository (DGR) as part of the long-term management of nuclear used fuel, with an in-service date of 2043 at the earliest.

### Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning the nuclear generating stations after the end of their service lives, as well as the cost of managing L&ILW generated by the stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include a deferred dismantlement basis for decommissioning of the stations, whereby the reactors will be de-watered and de-fuelled immediately after the station has ceased operations and thereafter will remain in a safe state condition for a 30-year period, prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of the ultimate long-term management of these wastes. The current assumptions used to establish the accrued costs for the management of L&ILW include an L&ILW DGR to be owned and operated by OPG. Agreement was previously reached with local municipalities for OPG to develop a DGR for the long-term management of L&ILW adjacent to OPG's Western Waste Management Facility in Kincardine, Ontario. The environmental assessment process for the proposed DGR is continuing.

### Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their services lives. The liability is based on third-party cost estimates following a review of plant sites and an assessment of required clean-up and restoration activities. For the purposes of measuring the non-nuclear fixed asset removal liability, thermal asset removal activities are assumed to take place approximately over the next one to 15 years.

As discussed in Note 3, OPG updated the fixed asset removal liabilities for the thermal generating stations as at December 31, 2017. The resulting decrease in the liabilities of $30 million as at December 31, 2017 was determined by discounting the net decrease in future cash flows using weighted average discount rates ranging from 3.41 percent to 5.58 percent reflected in the existing liability.

### Ontario Nuclear Funds Agreement

In accordance with the ONFA, OPG sets aside and invests funds that are held in segregated custodian and trustee accounts specifically for discharging its life cycle obligation for nuclear decommissioning and long-term nuclear waste management. The Used Fuel Segregated Fund and the Decommissioning Segregated Fund were established under

the ONFA for this purpose. OPG makes contributions to the Nuclear Segregated Funds based on the approved ONFA reference plan in effect. ONFA reference plans are subject to approval by the Province.

Since inception, OPG has been making quarterly payments to the Used Fuel Segregated Fund over the assumed lives of its nuclear generating stations, as specified in the ONFA, including contributions to the Ontario NFWA Trust (NFWA Trust) established by OPG pursuant to the NFWA. The NFWA Trust forms part of the Used Fuel Segregated Fund, with any OPG contributions to the Used Fuel Segregated Fund, as well as any portion of the fund currently not in the NFWA Trust, being able to be applied towards the NFWA Trust's annual contribution requirements pursuant to the NFWA. Required funding of the Used Fuel Segregated Fund for 2017 was nil (2016 – $150 million). ONFA requirements have resulted in the majority of the underlying used fuel management obligation being funded through OPG contributions over the initial estimated useful lives of the nuclear generating stations assumed in the ONFA, which did not reflect subsequent extensions to the nuclear station lives to reflect refurbishment and life extension decisions.

OPG has not been required to make contributions to the Decommissioning Segregated Fund, which was fully funded at its inception through an initial contribution made by the OEFC, an agency of the Province, and, taking into account asset performance and changes in underlying funding obligation over time, at the time of every subsequent approved ONFA reference plan.

The 2017 ONFA Reference Plan was approved by the Province in December 2016, with an effective date of January 1, 2017. Based on the funded status of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund reflecting the life cycle liability estimates per the 2017 ONFA Reference Plan, no overall contributions to either fund are currently required starting in 2017. Contributions may be required in the future should either or both of the funds be in an underfunded position when a new reference plan is prepared.

The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge its existing nuclear waste management and nuclear facilities decommissioning obligations. As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The Provincial Guarantee provides for any shortfall between the CNSC consolidated financial guarantee requirement and the value of the Nuclear Segregated Funds. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount, if any, of the Provincial Guarantee. The value of the Provincial Guarantee amount in effect through to the end of 2017 was $1,551 million. Based on this guarantee amount, OPG paid a guarantee fee of $8 million to the Province for each of 2017 and 2016.

The investments in the Nuclear Segregated Funds include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure, real estate, and agriculture. The Nuclear Segregated Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Segregated Funds remains the primary goal. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

Decommissioning Segregated Fund

Under the ONFA, OPG is wholly responsible for cost estimate changes and investment returns in the Decommissioning Segregated Fund. As at December 31, 2017 and 2016, the Decommissioning Segregated Fund was in an overfunded position.

Upon termination of the ONFA, the Province has the sole right to any excess funds in the Decommissioning Segregated Fund, which is the excess of the fair market value of the fund's assets over the underlying estimated future costs, as per the most recently approved ONFA reference plan. Accordingly, when the Decommissioning Segregated Fund is overfunded, OPG limits the fund earnings recognized in the consolidated financial statements by recording an amount due to the Province, such that the asset recognized for the fund on the consolidated balance

sheet is equal to the cost estimate of the liability based on the most recently approved ONFA reference plan. Additionally, OPG recognizes the portion of the surplus that it may direct to the Used Fuel Segregated Fund, which is possible when the surplus in the Decommissioning Segregated Fund is such that the underlying liabilities, as defined by the most recently approved ONFA reference plan, are at least 120 percent funded. In those circumstances, OPG may direct, at the time a new reference plan is approved, up to 50 percent of the surplus over 120 percent to the Used Fuel Segregated Fund, with the OEFC entitled to a distribution of an equal amount. Therefore, when the Decommissioning Segregated Fund is at least 120 percent funded, OPG recognizes 50 percent of the excess greater than 120 percent in income, up to the amount by which the Used Fuel Segregated Fund is underfunded. Based on the 2017 ONFA Reference Plan, the Used Fuel Segregated Fund was in a marginally overfunded position as at December 31, 2017 and 2016. As a result, OPG recognized a due to the Province amount such that the Decommissioning Segregated Fund asset on the consolidated balance sheet as at December 31, 2017 and 2016 was limited to the value of the underlying funding liability per the 2017 ONFA Reference Plan. This payable to the Province may be reduced in subsequent periods in the event that the Decommissioning Segregated Fund earns less than its target rate of return, a new ONFA reference plan is approved with a higher underlying funding liability, or the Used Fuel Segregated Fund changes to an underfunded status. When the Decommissioning Segregated Fund is underfunded, the earnings on the fund reflect actual fund returns based on the market value of the assets.

When the Decommissioning Segregated Fund is in an overfunded status of less than 120 percent, OPG recognizes its annual earnings on the fund at 3.25 percent plus the long-term Ontario Consumer Price Index (CPI) specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability. The same treatment is applied to the Decommissioning Segregated Fund when it is in an overfunded status of greater than 120 percent, if the Used Fuel Segregated Fund is fully funded.

Used Fuel Segregated Fund

OPG is responsible for cost increases in the funding liability for used fuel waste management under the ONFA, subject to specified graduated liability thresholds, pursuant to which the Province limits OPG's total financial exposure for the first 2.23 million nuclear used fuel bundles at approximately $15.7 billion in present value dollars as at December 31, 2017. The graduated liability thresholds do not apply to used fuel bundles beyond the 2.23 million threshold.

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Segregated Fund at 3.25 percent plus the change in the Ontario CPI, as defined by ONFA, for funding related to the first 2.23 million used fuel bundles, (committed return). OPG recognizes the committed return on the Used Fuel Segregated Fund as earnings on the Nuclear Segregated Funds. The difference between the committed return and the actual market return determined based on the fair value of the fund assets related to the first 2.23 million used fuel bundles is recorded as due to or due from the Province. This amount due to or due from the Province represents the amount that would be paid to or received from the Province if the committed return were to be settled as at the consolidated balance sheets date. The 2.23 million threshold represents the estimated total life cycle fuel bundles based on the initial estimated useful lives of the nuclear stations assumed in the ONFA.

As prescribed under the ONFA, OPG's contributions for fuel bundles in excess of 2.23 million are not subject to the rate of return guaranteed by the Province, and earn a return based on changes in the market value of the assets of the Used Fuel Segregated Fund.

If there is a surplus in the Used Fuel Segregated Fund such that the liabilities, as defined by the most recently approved ONFA reference plan, are at least 110 percent funded, the Province, has the right, at any time, to access the excess amount greater than 110 percent. Upon termination of the ONFA, the Province is entitled to any surplus in the fund, which is the excess of the fair market value of the Used Fuel Segregated Fund assets over the estimated future costs, as per the most recently approved ONFA reference plan. Neither OPG nor the Province has a right to direct any amounts from the Used Fuel Segregated Fund to the Decommissioning Segregated Fund. Therefore, when the Used Fuel Segregated Fund is overfunded, OPG limits the earnings it recognizes by recording an amount

due to the Province, such that the asset recognized for the fund on the consolidated balance sheets is equal to the cost estimate of the funding liability per the most recently approved ONFA reference plan. This results in OPG recognizing annual earnings on the fund at 3.25 percent plus the long-term Ontario CPI specified in the most recently approved ONFA reference plan, which is the rate of growth in the underlying funding liability, when the fund is overfunded.

As at December 31, 2017 and 2016, the Used Fuel Segregated Fund was marginally overfunded based on the 2017 ONFA Reference Plan, and OPG recognized a due to the Province amount such that the asset recognized for the fund was limited to the value of the underlying funding liability. This payable to the Province may be reduced in subsequent periods in the event that the Used Fuel Segregated Fund earns less than its target rate of return or in the event that a new ONFA reference plan is approved with a higher underlying funding liability.

### Nuclear Segregated Funds

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

| | Fair Value | |
|---|---|---|
| *(millions of dollars)* | **2017** | **2016** |
| Decommissioning Segregated Fund | **9,099** | 8,317 |
| Due to Province – Decommissioning Segregated Fund | **(1,933)** | (1,477) |
| | **7,166** | 6,840 |
| Used Fuel Segregated Fund [1] | **12,087** | 11,082 |
| Due to Province – Used Fuel Segregated Fund | **(2,529)** | (1,938) |
| | **9,558** | 9,144 |
| Total Nuclear Segregated Funds | **16,724** | 15,984 |
| Less: current portion | **23** | 24 |
| Non-current Nuclear Segregated Funds | **16,701** | 15,960 |

[1] The NFWA Trust represents $3,882 million as at December 31, 2017 (2016 – $3,688 million) of the Used Fuel Segregated Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Segregated Funds as at December 31 is as follows:

| | Fair Value | |
|---|---|---|
| *(millions of dollars)* | **2017** | **2016** |
| Cash and cash equivalents and short-term investments | **227** | 354 |
| Real assets | **2,357** | 1,989 |
| Pooled funds | **1,713** | 1,329 |
| Marketable equity securities | **10,457** | 9,503 |
| Fixed income securities | **6,405** | 6,181 |
| Net receivables/payables | **27** | 43 |
| | **21,186** | 19,399 |
| Due to Province | **(4,462)** | (3,415) |
| | **16,724** | 15,984 |

The historical cost, gross unrealized aggregate appreciation and depreciation of investment, gross unrealized foreign exchange gains, and fair value of the Nuclear Segregated Funds as at December 31, 2017 and 2016 are summarized as follows:

| *(millions of dollars)* | **Decommissioning Segregated Fund** | **2017 Used Fuel Segregated Fund** | **Total** |
|---|---|---|---|
| Historical cost | **7,327** | **9,902** | **17,229** |
| Gross unrealized gains (losses) | | | |
| Aggregate appreciation | **1,789** | **2,188** | **3,977** |
| Aggregate depreciation | **(134)** | **(180)** | **(314)** |
| Foreign exchange | **117** | **177** | **294** |
| | **9,099** | **12,087** | **21,186** |
| Due to Province | **(1,933)** | **(2,529)** | **(4,462)** |
| Total fair value | **7,166** | **9,558** | **16,724** |
| Less: current portion | **5** | **18** | **23** |
| Non-current fair value | **7,161** | **9,540** | **16,701** |

| *(millions of dollars)* | **Decommissioning Segregated Fund** | **2016 Used Fuel Segregated Fund** | **Total** |
|---|---|---|---|
| Historical cost | 6,896 | 9,385 | 16,281 |
| Gross unrealized gains (losses) | | | |
| Aggregate appreciation | 1,326 | 1,564 | 2,890 |
| Aggregate depreciation | (165) | (222) | (387) |
| Foreign exchange | 260 | 355 | 615 |
| | 8,317 | 11,082 | 19,399 |
| Due to Province | (1,477) | (1,938) | (3,415) |
| Total fair value | 6,840 | 9,144 | 15,984 |
| Less: current portion | 8 | 16 | 24 |
| Non-current fair value | 6,832 | 9,128 | 15,960 |

Net realized and unrealized gains or losses from investments for the years ended December 31, 2017 and 2016 are summarized as follows:

| *(millions of dollars)* | 2017 Decommissioning Segregated Fund | 2017 Used Fuel Segregated Fund | 2017 Total |
|---|---|---|---|
| **Net realized gains** | | | |
| Realized gains excluding foreign exchange | **198** | **245** | **443** |
| Realized foreign exchange gains | **54** | **65** | **119** |
| Net realized gains | **252** | **310** | **562** |
| **Net unrealized gains** | | | |
| Unrealized gains excluding foreign exchange | **494** | **666** | **1,160** |
| Unrealized foreign exchange losses | **(143)** | **(178)** | **(321)** |
| Net unrealized gains | **351** | **488** | **839** |

| *(millions of dollars)* | 2016 Decommissioning Segregated Fund | 2016 Used Fuel Segregated Fund | 2016 Total |
|---|---|---|---|
| **Net realized gains** | | | |
| Realized gains excluding foreign exchange | 84 | 180 | 264 |
| Realized foreign exchange gains | 30 | 41 | 71 |
| Net realized gains | 114 | 221 | 335 |
| **Net unrealized gains** | | | |
| Unrealized gains excluding foreign exchange | 360 | 442 | 802 |
| Unrealized foreign exchange losses | (165) | (216) | (381) |
| Net unrealized gains | 195 | 226 | 421 |

The change in the Nuclear Segregated Funds for the years ended December 31 is as follows:

| *(millions of dollars)* | Fair Value 2017 | Fair Value 2016 |
|---|---|---|
| Decommissioning Segregated Fund, beginning of year | **6,840** | 6,549 |
| Increase in fund due to return on investments | **807** | 505 |
| Decrease in fund due to reimbursement of eligible expenditures | **(25)** | (22) |
| Increase in due to Province | **(456)** | (192) |
| Decommissioning Segregated Fund, end of year | **7,166** | 6,840 |
| Used Fuel Segregated Fund, beginning of year | **9,144** | 8,587 |
| Increase in fund due to contributions made | **-** | 150 |
| Increase in fund due to return on investments | **1,059** | 690 |
| Decrease in fund due to reimbursement of eligible expenditures | **(54)** | (48) |
| Increase in due to Province | **(591)** | (235) |
| Used Fuel Segregated Fund, end of year | **9,558** | 9,144 |

The earnings from the Nuclear Segregated Funds during 2017 and 2016 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Segregated Funds for the years ended December 31 are as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Decommissioning Segregated Fund | **351** | 313 |
| Used Fuel Segregated Fund | **468** | 455 |
| Bruce Lease Net Revenues Variance Account | **(18)** | (22) |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **801** | 746 |

## 9. INCOME TAXES

OPG follows the liability method of accounting for income taxes. The Company records an offsetting regulatory asset or regulatory liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

A reconciliation between the statutory and the effective rate of income taxes is as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Income before income taxes | **1,090** | 621 |
| Combined Canadian federal and provincial statutory enacted income tax rates | **26.5%** | 26.5% |
| Statutory income tax rates applied to accounting income | **289** | 165 |
| (Decrease) increase in income taxes resulting from: | | |
| Income tax (recovery) expense deferred in regulatory assets and regulatory liabilities | **(20)** | 65 |
| Scientific Research and Experimental Development investment tax credits | **(47)** | (48) |
| Manufacturing and processing credit | **(16)** | (9) |
| Other | **3** | (5) |
| | **(80)** | 3 |
| Income tax expense | **209** | 168 |
| Effective rate of income taxes | **19.2%** | 27.0% |

Significant components of the income tax expense are presented in the table below:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Current income tax expense | **190** | 204 |
| Deferred income tax expense (recovery) | **19** | (36) |
| Income tax expense | **209** | 168 |

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Deferred income tax assets: | | |
| Fixed asset removal and nuclear waste management liabilities | **5,096** | 4,861 |
| Other assets and liabilities | **2,057** | 1,813 |
| | **7,153** | 6,674 |
| Deferred income tax liabilities: | | |
| Property, plant and equipment and intangible assets | **(1,923)** | (1,807) |
| Nuclear fixed asset removal and nuclear waste management funds | **(4,181)** | (3,996) |
| Other assets and liabilities | **(1,928)** | (1,700) |
| | **(8,032)** | (7,503) |
| Net deferred income tax liabilities | **(879)** | (829) |

During 2017, OPG recorded an increase in the deferred income tax liability for income taxes that is expected to be recovered through regulated prices charged to customers of $59 million (2016 – $46 million). Since these deferred income taxes are expected to be recovered through future regulated prices, OPG recorded a corresponding increase to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2017 and 2016 was not impacted.

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **January 1:** | | |
| Deferred income tax liabilities on temporary differences related to regulated operations | **627** | 592 |
| Deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities | **211** | 200 |
| | **838** | 792 |
| **Changes during the year:** | | |
| Increase in deferred income tax liabilities on temporary differences related to regulated operations | **44** | 35 |
| Increase in deferred income tax liabilities on temporary differences related to the regulatory asset for the deferred income tax liabilities | **15** | 11 |
| Balance as at December 31 | **897** | 838 |

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained upon examination by the taxing authorities based on the technical merits of the position. The current and deferred income tax benefit is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Unrecognized tax benefits, beginning of year | **77** | 72 |
| Additions based on tax positions related to the current year | **21** | 19 |
| Additions for tax positions of prior years | **-** | 2 |
| Reductions for tax positions of prior years | **(20)** | (16) |
| Unrecognized tax benefits, end of year | **78** | 77 |

As at December 31, 2017, OPG's unrecognized tax benefits were $78 million (2016 – $77 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2017, OPG had recorded interest on unrecognized tax benefits of $8 million (2016 – $8 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2013.

OPG paid $195 million in income taxes, net of tax refunds, during 2017 (2016 – $98 million).

## 10. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, are as follows:

| | 2017 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Gains and Losses on Cash Flow Hedges** | **Pension and OPEB** | **Available-for-sale Securities** | **Total** |
| AOCL, beginning of year | **(87)** | **(207)** | **(1)** | **(295)** |
| Actuarial loss on remeasurement of liabilities for pension and OPEB | **-** | **(23)** | **-** | **(23)** |
| Unrealized loss on available-for-sale securities | **-** | **-** | **(8)** | **(8)** |
| Amounts reclassified from AOCL | **18** | **10** | **-** | **28** |
| Other comprehensive income (loss) for the year | **18** | **(13)** | **(8)** | **(3)** |
| Reclassification of non-controlling interest on change in ownership interest *(Note 22)* | **3** | **-** | **-** | **3** |
| AOCL, end of year | **(66)** | **(220)** | **(9)** | **(295)** |

| | 2016 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Unrealized Gains and Losses on Cash Flow Hedges** | **Pension and OPEB** | **Available-for-sale Securities** | **Total** |
| AOCL, beginning of year | (106) | (213) | - | (319) |
| Actuarial loss on remeasurement of liabilities for pension and OPEB | - | (6) | - | (6) |
| Unrealized loss on available-for-sale securities | - | - | (1) | (1) |
| Amounts reclassified from AOCL | 19 | 12 | - | 31 |
| Other comprehensive income (loss) for the year | 19 | 6 | (1) | 24 |
| AOCL, end of year | (87) | (207) | (1) | (295) |

The significant amounts reclassified out of each component of AOCL, net of income taxes, during December 31, 2017 and 2016 are as follows:

| *(millions of dollars)* | Amount Reclassified from AOCL 2017 | 2016 | Statement of Income Line Item |
|---|---|---|---|
| Amortization of losses from cash flow hedges | | | |
| Losses | **20** | 21 | Net interest expense |
| Income tax recovery | **(2)** | (2) | Income tax expense |
| | **18** | 19 | |
| Amortization of amounts related to pension and OPEB | | | |
| Actuarial losses and past service costs | **13** | 16 | See (1) below |
| Income tax recovery | **(3)** | (4) | Income tax expense |
| | **10** | 12 | |
| Total reclassifications for the year | **28** | 31 | |

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 11 for additional details).

## 11. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

### Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by the Audit and Risk Committee of OPG's Board of Directors at least annually and includes a discussion of investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective of meeting obligations of the plan as they come due. The pension fund assets are invested in four categories of asset classes. The first category is liability hedging assets, which are intended to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended to obtain higher investment returns compared to the returns expected for liability hedging assets. The third category is real assets, which offer exposure to the combined characteristics of liability hedging and return enhancing assets. The fourth category is return diversifying strategies, which are intended to improve the overall return of the pension fund while mitigating the downside market risk.

To achieve the above objective, OPG has adopted the following target strategic asset allocation:

| | Target |
|---|---|
| Asset Class | |
| Liability Hedging Assets | 34% |
| Return Enhancing Assets | 31% |
| Real Assets | 20% |
| Return Diversifying Assets | 15% |

The plan may use derivatives for risk management or strategic purposes, where such activity is consistent with the plan's investment objectives.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian government bonds, government agency bonds, real return bonds, and corporate bonds. Equity securities are diversified across

Canadian, US, and Global stocks. There are also real estate, infrastructure, and agriculture portfolios that represent approximately 12 percent of the total pension fund assets as at December 31, 2017. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is managed by risk tolerance guidelines, which require that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes, but is not limited to, the following activities:

- Periodic asset/liability management and strategic asset allocation studies
- Monitoring of funding levels and funding ratios
- Monitoring compliance with asset allocation guidelines and investment management agreements
- Monitoring asset class performance against asset class benchmarks
- Monitoring investment manager performance against benchmarks
- Monitoring of risk tolerance guidelines

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the fund's asset allocation, as well as the return expectations considering long-term risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

**Fair Value Measurements**

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the assets and liabilities. Refer to Note 13 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

| | December 31, 2017 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Cash and cash equivalents | **377** | **-** | **-** | **377** |
| Short-term investments | **-** | **9** | **-** | **9** |
| Fixed income | | | | |
| Corporate debt securities | **-** | **521** | **-** | **521** |
| Government bonds | **-** | **3,476** | **-** | **3,476** |
| Equities | | | | |
| Canadian | **1,441** | **329** | **-** | **1,770** |
| US | **1,551** | **-** | **-** | **1,551** |
| Global | **1,681** | **-** | **-** | **1,681** |
| Pooled funds | **459** | **105** | **-** | **564** |
| Other | **15** | **-** | **-** | **15** |
| | **5,524** | **4,440** | **-** | **9,964** |
| Investments measured at NAV [1] | | | | **4,221** |
| | | | | **14,185** [2] |

[1] Represents investments measured at fair value using Net Asset Value (NAV) as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

| | December 31, 2016 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| Cash and cash equivalents | 690 | - | - | 690 |
| Fixed income | | | | |
| Corporate debt securities | - | 407 | - | 407 |
| Government bonds | - | 3,483 | - | 3,483 |
| Equities | | | | |
| Canadian | 1,449 | 291 | - | 1,740 |
| US | 1,495 | - | - | 1,495 |
| Global | 1,643 | - | - | 1,643 |
| Pooled funds | 118 | 413 | - | 531 |
| | 5,395 | 4,594 | - | 9,989 |
| Investments measured at NAV [1] | | | | 3,504 |
| | | | | 13,493 [2] |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to the total fair value of plan assets presented in tables following.

[2] The table above excludes pension fund receivables and payables.

## Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs, together with the key assumptions used in determining these amounts, are presented in the following tables:

| | Registered and Supplementary Pension Plans | | Other Post-Employment Benefits | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| *Weighted Average Assumptions – Benefit Obligations at Year-End* | | | | |
| Discount rate for projected benefit obligation | **3.57 %** | 3.90 % | **3.60 %** | 3.94 % |
| Salary schedule escalation rate - initial rate [1] | **1.90 %** | 1.80 % | **1.90 %** | 1.80 % |
| - thereafter | **2.50 %** | 2.50 % | **2.50 %** | 2.50 % |
| Rate of cost of living increase to pensions | **2.00 %** | 2.00 % | **n/a** | n/a |
| Initial health care trend rate | **n/a** | n/a | **5.80 %** | 5.90 % |
| Ultimate health care trend rate | **n/a** | n/a | **4.32 %** | 4.32 % |
| Year ultimate health care trend rate reached | **n/a** | n/a | **2030** | 2030 |
| Rate of increase in disability benefits | **n/a** | n/a | **2.00 %** | 2.00 % |

[1] Per year to December 31, 2021.

| | Registered and Supplementary Pension Plans | | Other Post-Employment Benefits | |
|---|---|---|---|---|
| | 2017 | 2016 | 2017 | 2016 |
| *Weighted Average Assumptions – Costs for the Year* | | | | |
| Expected return on plan assets, net of expenses | **6.00 %** | 6.00 % | **n/a** | n/a |
| Discount rate for current service cost | **4.15 %** | 4.10 % | **4.03 %** | 4.13 % |
| Discount rate for interest on projected benefit obligation | **3.37 %** | 4.10 % | **3.53 %** | 4.13 % |
| Discount rate for interest on current service cost | **3.95 %** | 4.10 % | **3.85 %** | 4.13 % |
| Salary schedule escalation rate - initial rate [1] | **1.80 %** | 1.60 % | **1.80 %** | 1.60 % |
| - thereafter | **2.50 %** | 2.50 % | **2.50 %** | 2.50 % |
| Rate of cost of living increase to pensions | **2.00 %** | 2.00 % | **n/a** | n/a |
| Initial health care trend rate | **n/a** | n/a | **5.90 %** | 6.00 % |
| Ultimate health care trend rate | **n/a** | n/a | **4.32 %** | 4.33 % |
| Year ultimate health care trend rate reached | **n/a** | n/a | **2030** | 2030 |
| Rate of increase in disability benefits | **n/a** | n/a | **2.00 %** | 2.00 % |
| Expected average remaining service life for employees (years) | **12** | 12 | **13** | 13 |

[1] Per year to December 31, 2021.

| *(millions of dollars)* | Registered Pension Plans 2017 | 2016 | Supplementary Pension Plans 2017 | 2016 | Other Post-Employment Benefits 2017 | 2016 |
|---|---|---|---|---|---|---|
| *Components of Cost Recognized for the Year* | | | | | | |
| Current service costs | **274** | 277 | **7** | 7 | **67** | 67 |
| Interest on projected benefit obligation | **548** | 634 | **11** | 12 | **106** | 133 |
| Expected return on plan assets, net of expenses | **(766)** | (734) | **-** | - | **-** | - |
| Amortization of past service costs [1] | **-** | - | **-** | - | **1** | 1 |
| Amortization of net actuarial loss [1] | **183** | 192 | **6** | 4 | **-** | 19 |
| Recognition of LTD net actuarial loss (gain) | **-** | **-** | **-** | **-** | **11** | (52) |
| Costs recognized [2] | **239** | 369 | **24** | 23 | **185** | 168 |

[1] The amortization of past service costs and net actuarial loss was recognized as an increase to OCI. This increase was partially offset by the impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] Excludes the impact of regulatory variance and deferral accounts discussed in Note 5.

Total benefit costs, including the impact of the Pension & OPEB Cash Payment Variance Account and the Pension & OPEB Cash Versus Accrual Differential Deferral Account, for the years ended December 31 are as follows:

| *(millions of dollars)* | 2017 | 2016 |
|---|---|---|
| Registered pension plans | **239** | 369 |
| Supplementary pension plans | **24** | 23 |
| Other post-employment benefits | **185** | 168 |
| Pension & OPEB Cash Payment Variance Account *(Note 5)* | **81** | 86 |
| Pension & OPEB Cash Versus Accrual Differential Deferral Account *(Note 5)* | **(117)** | (182) |
| Pension and other post-employment benefit costs | **412** | 464 |

The pension and OPEB obligations and the pension fund assets measured as at December 31 are as follows:

| *(millions of dollars)* | Registered Pension Plans 2017 | Registered Pension Plans 2016 | Supplementary Pension Plans 2017 | Supplementary Pension Plans 2016 | Other Post-Employment Benefits 2017 | Other Post-Employment Benefits 2016 |
|---|---|---|---|---|---|---|
| *Change in Plan Assets* | | | | | | |
| Fair value of plan assets at beginning of year | **13,506** | 13,160 | **-** | - | **-** | - |
| Contributions by employer | **214** | 255 | **14** | 15 | **94** | 93 |
| Contributions by employees | **97** | 85 | **-** | - | **-** | - |
| Actual return on plan assets, net of expenses | **1,207** | 714 | **-** | - | **-** | - |
| Benefit payments | **(761)** | (708) | **(14)** | (15) | **(94)** | (93) |
| Fair value of plan assets at end of year | **14,263** | 13,506 | **-** | - | **-** | - |
| *Change in Projected Benefit Obligations* | | | | | | |
| Projected benefit obligations at beginning of year | **16,199** | 15,475 | **336** | 299 | **2,992** | 3,188 |
| Employer current service costs | **274** | 277 | **7** | 7 | **67** | 67 |
| Contributions by employees | **97** | 85 | **-** | - | **-** | - |
| Interest on projected benefit obligation | **548** | 634 | **11** | 12 | **106** | 133 |
| Benefit payments | **(761)** | (708) | **(14)** | (15) | **(94)** | (93) |
| Net actuarial loss (gain) | **987** | 436 | **16** | 33 | **119** | (303) |
| Projected benefit obligations at end of year | **17,344** | 16,199 | **356** | 336 | **3,190** | 2,992 |
| Funded status – deficit at end of year | **(3,081)** | (2,693) | **(356)** | (336) | **(3,190)** | (2,992) |

The following table provides the pension and OPEB liabilities and their classification on the consolidated balance sheets as at December 31:

| *(millions of dollars)* | Registered Pension Plans 2017 | Registered Pension Plans 2016 | Supplementary Pension Plans 2017 | Supplementary Pension Plans 2016 | Other Post-Employment Benefits 2017 | Other Post-Employment Benefits 2016 |
|---|---|---|---|---|---|---|
| Current liabilities | **-** | - | **(14)** | (17) | **(98)** | (95) |
| Non-current liabilities | **(3,081)** | (2,693) | **(342)** | (319) | **(3,092)** | (2,897) |
| Total liabilities | **(3,081)** | (2,693) | **(356)** | (336) | **(3,190)** | (2,992) |

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2017 are $16,005 million and $333 million, respectively (2016 – $14,909 million and $293 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset, discussed in Note 5, for the years ended December 31, on a pre-tax basis:

| *(millions of dollars)* | Registered Pension Plans 2017 | Registered Pension Plans 2016 | Supplementary Pension Plans 2017 | Supplementary Pension Plans 2016 | Other Post-Employment Benefits 2017 | Other Post-Employment Benefits 2016 |
|---|---|---|---|---|---|---|
| *Changes in plan assets and benefit obligations recognized in OCI* | | | | | | |
| Current year net actuarial loss (gain) | **546** | 456 | **16** | 33 | **108** | (251) |
| Amortization of net actuarial loss | **(183)** | (192) | **(6)** | (4) | **-** | (19) |
| Amortization of past service costs | **-** | - | **-** | - | **(1)** | (1) |
| Total decrease (increase) in OCI | **363** | 264 | **10** | 29 | **107** | (271) |
| Less: increase (decrease) in Pension and OPEB Regulatory Asset *(Note 5)* | **352** | 253 | **9** | 27 | **102** | (250) |
| Net decrease (increase) in OCI (pre-tax) | **11** | 11 | **1** | 2 | **5** | (21) |

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31, on a pre-tax basis:

| *(millions of dollars)* | Registered Pension Plans 2017 | Registered Pension Plans 2016 | Supplementary Pension Plans 2017 | Supplementary Pension Plans 2016 | Other Post-Employment Benefits 2017 | Other Post-Employment Benefits 2016 |
|---|---|---|---|---|---|---|
| *Unamortized amounts recognized in AOCL* | | | | | | |
| Past service costs | **-** | - | **-** | - | **4** | 5 |
| Net actuarial loss | **3,650** | 3,287 | **116** | 106 | **378** | 270 |
| Total recognized in AOCL | **3,650** | 3,287 | **116** | 106 | **382** | 275 |
| Less: Pension and OPEB Regulatory Asset *(Note 5)* | **3,391** | 3,039 | **109** | 100 | **355** | 253 |
| Net recognized in AOCL (pre-tax) | **259** | 248 | **7** | 6 | **27** | 22 |

The following table provides the components of OPG's AOCL and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2018, on a pre-tax basis:

| *(millions of dollars)* | Registered Pension Plans | Supplementary Pension Plans | Other Post-Employment Benefits |
|---|---|---|---|
| Past service costs | **-** | **-** | **1** |
| Net actuarial loss | **198** | **7** | **6** |
| Total increase in OCI | **198** | **7** | **7** |
| Less: estimated decrease in Pension and OPEB Regulatory Asset | **184** | **6** | **6** |
| Net increase in OCI (pre-tax) | **14** | **1** | **1** |

The most recently filed actuarial valuation, for funding purposes, of the OPG registered pension plan, as at January 1, 2017, was filed with the FSCO in September 2017. The next filed funding valuation must have an effective date no later than January 1, 2020. For 2018, OPG's required contribution to its registered pension plan is expected to be $215 million. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $353 million as at December 31, 2017 (2016 – $349 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2017 are as follows:

| *(millions of dollars)* | **Registered Pension Plans** | **Supplementary Pension Plans** | **Other Post-Employment Benefits** |
|---|---|---|---|
| 2018 | 676 | 15 | 98 |
| 2019 | 696 | 15 | 101 |
| 2020 | 722 | 15 | 105 |
| 2021 | 747 | 16 | 108 |
| 2022 | 764 | 16 | 111 |
| 2023 through 2027 | 4,397 | 86 | 633 |

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2017 OPEB costs of $40 million (2016 – $45 million) or a decrease in the service and interest components of the 2017 OPEB costs of $29 million (2016 – $33 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation as at December 31, 2017 of $592 million (2016 – $560 million) or a decrease in the projected OPEB obligation as at December 31, 2017 of $451 million (2016 – $426 million).

## 12. RISK MANAGEMENT AND DERIVATIVES

OPG is exposed to risks related to changes in market interest rates on debt expected to be issued in the future and movements in foreign currency that affect the Company's assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks. Derivatives are used as hedging instruments, as well as for trading purposes.

Interest rate risk is the risk that the value of assets and liabilities can change due to movements in related interest rates. Interest rate risk for OPG arises with the need to refinance existing debt and/or undertake new financing. The management of these risks includes using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, US dollars. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when appropriate, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Market participants in the IESO spot market provide collateral in accordance with the IESO prudential support requirements to cover funds that they might owe to the market. Although the credit exposure to the IESO represents a significant portion of OPG's accounts receivable, the Company's management accepts this risk due to the IESO's primary role in the Ontario electricity market. The remaining receivables exposure is to a diverse group of generally high quality counterparties. OPG's allowance for doubtful accounts as at December 31, 2017 was less than $1 million.

The fair value of the derivatives totalled a net liability of $20 million as at December 31, 2017 (December 31, 2016 – $24 million).

The following table shows the pre-tax amounts related to derivatives recorded in AOCL and net income for the years ended December 31:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **Cash flow hedges (recorded in AOCL)** | | |
| Reclassification of losses to net interest expense | **20** | 21 |
| **Commodity derivatives (recorded in net income)** | | |
| Realized losses in revenue | **(9)** | (12) |
| Unrealized gains (losses) in revenue | **3** | (3) |

Existing pre-tax net losses of $19 million deferred in AOCL as at December 31, 2017 are expected to be reclassified to net income within the next 12 months.

## 13. FAIR VALUE MEASUREMENTS

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial assets and liabilities into three levels, based on the inputs used in measuring the fair value of the financial assets and liabilities. The fair value hierarchy has the following levels:

- Level 1: Valuation of inputs is based on unadjusted quoted market prices observed in active markets for identical assets or liabilities.
- Level 2: Valuation is based on inputs other than quoted prices under Level 1 that are observable for the asset or liability, either directly or indirectly.
- Level 3: Valuation is based on inputs for the asset or liability that are not based on observable market data.

The fair value of financial instruments traded in active markets is based on quoted market prices as at the consolidated balance sheet dates. A market is regarded as active if quoted prices are readily and regularly available from an exchange, dealer, broker, industry group, pricing service, or regulatory agency, and those prices represent actual and regularly occurring market transactions on an arm's-length basis. The quoted market price used for financial assets held by OPG is the current bid price. These instruments are included in Level 1 and are comprised primarily of equity investments and fund investments.

For financial instruments for which quoted market prices are not directly available, fair values are estimated using forward price curves developed from observable market prices or rates. The estimation of fair value may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing as at the consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Pooled fund investments are valued at the unit values supplied by the pooled fund administrators. The unit values represent the underlying net assets at fair values, determined using closing market prices. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. If all significant inputs required to fair value an instrument are observable, the instrument is included in Level 2.

The following is a summary of OPG's financial instruments and their fair value as at December 31, 2017 and December 31, 2016:

| | Fair Value | | Carrying Value [1] | | |
|---|---|---|---|---|---|
| *(millions of dollars)* | **2017** | **2016** | **2017** | **2016** | **Balance Sheet Line Item** |
| Nuclear Segregated Funds (includes current portion) [2] | **16,724** | 15,984 | **16,724** | 15,984 | Nuclear fixed asset removal and nuclear waste management funds |
| Financing receivables | **1,179** | - | **1,179** | - | Financing receivables |
| Investment in Hydro One shares | **188** | 212 | **188** | 212 | Available-for-sale securities |
| Payable related to cash flow hedges | **(40)** | (48) | **(40)** | (48) | Long-term accounts payable and accrued charges |
| Long-term debt – OPG (includes current portion) | **(6,234)** | (6,033) | **(5,735)** | (5,520) | Long-term debt |
| Long-term debt – Fair Hydro Trust | **(601)** | - | **(601)** | - | Long-term debt |
| Other financial instruments | **(16)** | (18) | **(16)** | (18) | Various |

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other current assets, short-term debt, and accounts payable and accrued charges approximate their fair values due to the immediate or short-term maturity of these financial instruments.

[2] The Nuclear Segregated Funds are comprised of the Decommissioning Segregated Fund and the Used Fuel Segregated Fund. OPG's fair value of the Nuclear Segregated Funds is set not to exceed an amount equal to the funding liability pursuant to the ONFA when the Nuclear Segregated Funds are in a surplus position. Refer to Note 8 for further information.

The fair value of the Fair Hydro Trust long-term senior debt and OPG's long-term debt issued under the Medium Term Note Program are based on unadjusted quoted active market prices, which are considered Level 1 inputs. All other long-term debt instruments are determined based on a conventional pricing model, which is a function of future cash flows, the current market yield curve and term to maturity. These inputs are considered Level 2 inputs.

For the financing receivables related to the Investment Interest acquired from the IESO, fair value is estimated to equal the fair value of the underlying long-term debt due to the direct relationship between the asset and the debt instruments that financed the acquisition. The financing receivables are funded by both long-term senior debt issued by the Fair Hydro Trust to third parties and subordinated debt issued by the Trust to OPG and eliminated on consolidation. Therefore, the fair value of the portion of the financing receivables funded by the long-term senior debt is based on Level 1 inputs, while the portion funded by the subordinated debt has inputs that are based on indicative pricing from the market, which are considered Level 2 inputs.

If one or more of the significant inputs is not based on observable market data, the instrument is included in Level 3. Specific valuation techniques are used to value these instruments. Significant Level 3 inputs include: recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

The following tables present financial assets and financial liabilities measured at fair value in accordance with the fair value hierarchy as at December 31, 2017 and December 31, 2016:

| | December 31, 2017 | | | |
|---|---|---|---|---|
| *(millions of dollars)* | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **6,090** | **4,705** | **-** | **10,795** |
| Investments measured at NAV [1] | | | | **1,292** |
| | | | | **12,087** |
| Due to Province | | | | **(2,529)** |
| Used Fuel Segregated Fund, net | | | | **9,558** |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | **4,547** | **3,487** | **-** | **8,034** |
| Investments measured at NAV [1] | | | | **1,065** |
| | | | | **9,099** |
| Due to Province | | | | **(1,933)** |
| Decommissioning Segregated Fund, net | | | | **7,166** |
| Investment in available-for-sale securities | **188** | **-** | **-** | **188** |
| Other financial assets | **5** | **3** | **6** | **14** |
| **Liabilities** | | | | |
| Other financial liabilities | **(28)** | **(2)** | **-** | **(30)** |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

| *(millions of dollars)* | December 31, 2016 Level 1 | Level 2 | Level 3 | Total |
|---|---|---|---|---|
| **Assets** | | | | |
| *Used Fuel Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 5,602 | 4,394 | - | 9,996 |
| Investments measured at NAV [1] | | | | 1,086 |
| | | | | 11,082 |
| Due to Province | | | | (1,938) |
| Used Fuel Segregated Fund, net | | | | 9,144 |
| *Decommissioning Segregated Fund* | | | | |
| Investments measured at fair value, excluding investments measured at NAV | 4,171 | 3,243 | - | 7,414 |
| Investments measured at NAV [1] | | | | 903 |
| | | | | 8,317 |
| Due to Province | | | | (1,477) |
| Decommissioning Segregated Fund, net | | | | 6,840 |
| Investments in available-for-sale securities | 212 | - | - | 212 |
| Other financial assets | 6 | 2 | 9 | 17 |
| **Liabilities** | | | | |
| Other financial liabilities | (29) | (6) | - | (35) |

[1] Represents investments measured at fair value using NAV as a practical expedient, which have not been classified in the fair value hierarchy. The fair value amounts for these investments presented in this table are intended to permit the reconciliation of the fair value hierarchy to amounts presented on the consolidated balance sheets.

During the year ended December 31, 2017, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into or out of Level 3.

The following table presents the changes in OPG's net assets measured at fair value that are classified as Level 3 financial instruments.

| *(millions of dollars)* | Other financial instruments |
|---|---|
| Opening balance, January 1, 2017 | **9** |
| Unrealized losses included in revenue | **(3)** |
| Realized losses included in revenue | **(9)** |
| Purchases | **9** |
| Closing balance, December 31, 2017 | **6** |

## Nuclear Segregated Funds

The fair value of the investments within the Nuclear Segregated Funds' real assets portfolio is determined using appropriate valuation techniques, such as recent arm's-length market transactions, references to current fair values of other instruments that are substantially the same, discounted cash flow analyses, third-party independent appraisals, valuation multiples, or other valuation methods. Any control, size, liquidity or other discount premiums on the investments are considered in the determination of fair value.

The process of valuing investments for which no published market price exists is based on inherent uncertainties and the resulting values may differ from values that would have been used had a ready market existed for these investments. The values may also differ from the prices at which the investments may be sold.

The following are the classes of investments within the Nuclear Segregated Funds that are reported on the basis of NAV as at December 31, 2017:

| *(millions of dollars except where noted)* | Fair Value | Unfunded Commitments | Redemption Frequency | Redemption Notice |
|---|---|---|---|---|
| Real Assets | | | | |
| Infrastructure | **1,330** | **798** | **n/a** | **n/a** |
| Real Estate | **936** | **440** | **n/a** | **n/a** |
| Agriculture | **91** | **97** | **n/a** | **n/a** |
| Pooled Funds | | | | |
| Short-term Investments | **32** | **n/a** | **Daily** | **1 - 5 Days** |
| Fixed Income | **729** | **n/a** | **Daily** | **1 - 5 Days** |
| Equity | **952** | **n/a** | **Daily** | **1 - 5 Days** |
| Total | **4,070** | **1,335** | | |

The fair value of the pooled funds is classified as Level 2. Infrastructure, real estate and agriculture investments are measured using NAV as a practical expedient for determining their fair value.

Infrastructure

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through private investments in sectors such as energy, transportation, communication and utilities. The fair values of investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each infrastructure fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Real Estate

This asset class includes investments in funds and assets with an objective to generate a combination of long-term capital appreciation and current income, generally through investments in institutional-grade real estate property. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each real estate fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. For investments in private real estate corporations, shares may be redeemed through a pre-established redemption process. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Agriculture

This asset class includes investments in funds and assets with an objective to provide a differentiated return source, income yield, and inflation protection, generally through private investments in global farmland and timberland. The fair values of the investments in this class have been estimated using NAV of the Nuclear Segregated Funds' ownership interest in these investments. The investments in the respective funds are not redeemable. However, the Nuclear Segregated Funds may transfer any of their partnership interests/shares to another party, as stipulated in the partnership agreements and/or shareholders' agreements. Distributions from each agriculture fund will be received based on the operations of the underlying investments and/or as the underlying investments are liquidated. It is not possible to estimate when the underlying assets in this asset class will be liquidated.

Pooled Funds

This asset class represents investments in pooled funds, which primarily include a diversified portfolio of fixed income securities, issued mainly by Canadian corporations, and diversified portfolios of Emerging Market listed equity. The investment objective of the pooled funds is to achieve capital appreciation and income through professionally managed portfolios. The fair value of the investments in this class has been estimated using NAV per share of the investments. There are no significant restrictions on the ability to sell the investments in this class.

## 14. SHARE CAPITAL

Common Shares

As at December 31, 2017 and 2016, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder, the Province.

Class A Shares

The Company's Articles of Amalgamation were amended effective December 1, 2017 to allow for the creation and issuance of non-voting Class A shares to the Province in exchange for equity injections in OPG. All of the outstanding shares are owned directly by the Province and OPG is authorized to issue an unlimited number of Class A shares without nominal or par value. The Class A and common shares rank equally as to entitlement to dividends, and all dividends declared by OPG must be declared in equal amounts per share on all outstanding shares without preference or distinction. Upon the liquidation, dissolution or wind-up of OPG, whether voluntary or involuntary, the holders of Class A shares and common shares are entitled to share equally, on a share for share basis, in all distributions of property and assets without preference or distinction. Any issue of new class of shares is subject to the consent of the Province. OPG is entitled to redeem outstanding Class A shares as may be approved by OPG's Board of Directors.

In December 2017, OPG issued 12,217,616 Class A shares at a price of $42.46 per share to the Province for its equity injection in OPG, generating proceeds of $519 million. These proceeds were used by OPG to purchase the Fair Hydro Trust's subordinated debt in the amount of 44 percent of the total funding requirement for the Trust's acquisition of Investment Interest from the IESO in December 2017.

## 15. EARNINGS PER SHARE

Basic and diluted earnings per share are calculated by dividing net income attributable to the Shareholder by the weighted average number of shares outstanding.

Class A shares are included in the weighted average number of shares outstanding. The weighted average number of shares outstanding as at December 31, 2017 was 256.7 million (2016 – 256.3 million). There were no dilutive securities during the years ended December 31, 2017 and 2016.

## 16. COMMITMENTS AND CONTINGENCIES

### Litigation

On August 9, 2006, a Notice of Action and Statement of Claim filed with the Ontario Superior Court of Justice in the amount of $500 million was served against OPG and Bruce Power by British Energy Limited and British Energy International Holdings Limited (together British Energy). The action is for contribution and indemnity of any amounts British Energy was liable for in an arbitration against it by some of the owners of Bruce Power regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power (the Arbitration). Both the action and the Arbitration relate to corrosion to a steam generator unit discovered after OPG leased the Bruce nuclear generating stations to Bruce Power.

In 2012, the arbitrator found that British Energy was liable to the claimants for some of the damages they claimed. The final settlement amount was valued by British Energy at $71 million. In September 2014, British Energy amended its Statement of Claim (Amended Claim) to reduce the claim amount to $100 million to reflect that the purchasers of British Energy's interest in Bruce Power did not receive the full damages they originally claimed in the Arbitration. British Energy also added an allegation to its Amended Claim that OPG breached a covenant to maintain the steam generator between the time of the initial agreement to lease and the effective date of the lease in accordance with "Good Utility Practices".

In November 2016, British Energy obtained consent from Ontario Superior Court of Justice to a timetable for the remaining steps in the litigation, pursuant to which the matter must be set down for trial by December 31, 2018. OPG has delivered a statement of defence in accordance with an extension of the original June 30, 2017 delivery deadline set up in the timetable.

Various other legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of business activities.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably. While it is not possible to determine the ultimate outcome of the various pending actions, it is the Company's belief that their resolution is not likely to have a material adverse impact on its financial position.

### Guarantees

The Company and its joint venture partners have jointly guaranteed the financial performance of jointly owned entities related primarily to the payment of liabilities. As at December 31, 2017, the total amount of guarantees OPG provided to these entities was $82 million (December 31, 2016 − $83 million). OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time. Other guarantees have terms ending between 2019 and 2029. As at December 31, 2017, the potential impact of the fair value of these guarantees to income has been estimated to be negligible and OPG does not expect to make any payments associated with these guarantees.

## Contractual Obligations

OPG's contractual obligations as at December 31, 2017 are as follows:

| *(millions of dollars)* | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| Fuel supply agreements | 158 | 125 | 115 | 88 | 67 | 67 | 620 |
| Contributions to the OPG registered pension plan [1] | 215 | 219 | - | - | - | - | 434 |
| OPG long-term debt repayment | 398 | 368 | 663 | 413 | 172 | 3,721 | 5,735 |
| Interest on OPG long-term debt | 244 | 226 | 204 | 175 | 161 | 3,006 | 4,016 |
| Fair Hydro Trust senior debt repayment [2] | - | 601 | - | - | - | - | 601 |
| Interest on Fair Hydro Trust senior debt | 15 | 15 | - | - | - | - | 30 |
| Commitments related to Darlington Refurbishment project [3] | 457 | - | - | - | - | - | 457 |
| Commitments related to Ranney Falls GS project | 5 | - | - | - | - | - | 5 |
| Operating licences | 40 | 41 | 24 | 28 | 28 | 87 | 248 |
| Operating lease obligations | 28 | 24 | 24 | 22 | 22 | 79 | 199 |
| Unconditional purchase obligations | 62 | 59 | 56 | 5 | - | - | 182 |
| Accounts payable and accrued charges | 957 | 8 | - | - | - | 16 | 981 |
| Other | 47 | 28 | 2 | 1 | 1 | 64 | 143 |
| Total | 2,626 | 1,714 | 1,088 | 732 | 451 | 7,040 | 13,651 |

[1] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuation of the OPG registered pension plan as at January 1, 2017. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2020. The pension contributions are affected by various factors including market performance, changes in actuarial assumptions, plan experience, changes in the pension regulatory environment, and the timing of funding valuations. Funding requirements after 2019 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

[2] The notes were issued by the Fair Hydro Trust under an $800 million two-year revolving warehouse facility in December 2017. In February 2018, the Trust issued $500 million of senior notes payable to repay the majority of the outstanding balance of the revolving warehouse facility.

[3] Represents estimated currently committed costs to close the project, including accruals for completed work, demobilization of project staff and cancellation of existing contracts and material orders.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

### Lease Commitments

The Company leases the Bruce A and Bruce B nuclear generating stations to Bruce Power. Under the lease agreement, as amended in December 2015, Bruce Power has options to renew the lease up to the end of 2064. As per *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the difference between OPG's revenues and costs associated with the Bruce A and Bruce B nuclear generating stations is included in the determination of OPG's nuclear regulated prices established by the OEB. The OEB has determined that, since the Bruce nuclear generating stations are not prescribed under *Ontario Regulation 53/05*, these revenues, including lease revenues, and costs, including depreciation expense, are to be calculated on the basis of the manner in which they are recognized in OPG's consolidated financial statements, without the application of regulatory constructs. As such, the net book value of the assets for these stations is not included in the regulated rate base.

The net book value of PP&E on lease to Bruce Power as at December 31, 2017 was $2,962 million (2016 – $2,986 million). The net book value is largely comprise of asset retirement costs. Refer to Note 3 for further details on the change in the estimate for the ARO.

Collective Bargaining Agreements

The Company maintains labour agreements with the Power Workers' Union (PWU) and The Society of Energy Professionals (The Society). As of December 31, 2017, the PWU represented approximately 4,850 OPG regular employees or approximately 53 percent of OPG's regular workforce. The current collective agreement between OPG and the PWU has a three-year term, expiring on March 31, 2018. As at December 31, 2017, The Society represented approximately 3,250 OPG employees or approximately 35 percent of OPG's regular workforce. The current collective agreement between OPG and The Society has a three-year term, expiring on December 31, 2018.

## 17. BUSINESS SEGMENTS

Effective in the fourth quarter of 2017, OPG has the following six reportable business segments:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and Other Non-Generation
- Fair Hydro Trust

### Regulated – Nuclear Generation Segment

The Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering GS and the Darlington GS, both owned and operated by OPG. The business segment also includes revenue under the terms of a long-term lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue, fees for nuclear waste management, and revenue from heavy water sales and detritiation services. The segment also earns revenue from existing isotope sales contracts and ancillary services supplied by OPG from the nuclear stations it operates. Ancillary revenues are earned through voltage control and reactive support.

### Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management business segment reports the results of the Company's operations associated with the management of nuclear used fuel and L&ILW, the decommissioning of OPG's nuclear generating stations including the stations on lease to Bruce Power and other facilities, the management of the Nuclear Segregated Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense, which is the increase in the Nuclear Liabilities carried on the consolidated balance sheets in present value terms due to the passage of time, and earnings from the Nuclear Segregated Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs incremental costs related to used nuclear fuel and L&ILW, which increase the Nuclear Liabilities. OPG charges these incremental costs to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy from the Pickering and Darlington nuclear generating stations and earning revenue under the Bruce Power lease arrangement and related agreements. Since the incremental costs increase the Nuclear Liabilities reported in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated in the consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because OPG's costs associated with the Nuclear Liabilities are included in the OEB's determination of regulated prices for production from the Pickering and Darlington nuclear generating stations.

### Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's hydroelectric generating stations. The business segment comprises the results of 54 regulated hydroelectric generating stations located across a number of major river systems in the province.

In addition, the business segment includes ancillary and other revenues from OPG's regulated hydroelectric stations. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

### Contracted Generation Portfolio Segment

The Contracted Generation Portfolio business segment operates in Ontario, generating and selling electricity from the Company's generating stations that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an ESA or other long-term contracts with the IESO.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the PEC and Brighton Beach stations.

The business segment also includes ancillary revenues and other revenues from the stations included in the segment, which are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service, and other services.

### Services, Trading, and Other Non-Generation Segment

The Services, Trading, and Other Non-Generation business segment is a non-generation segment that is not subject to rate regulation. It includes the revenue and expenses related to OPG's trading and other non-hedging activities.

As part of these activities, OPG transacts with counterparties in Ontario and neighbouring energy markets in predominantly short-term trading activities of typically one year or less in duration. These activities relate to electricity that is purchased and sold at the Ontario border, financial energy trades, financial risk management energy product revenues, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. The results of this subsidiary are reported in this segment. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value on the consolidated balance sheets with changes in fair value recorded in the revenue of this segment.

In addition, the segment includes revenue from real estate rentals and non-regulated services, gains or losses on disposition of non-regulated real estate assets, costs associated with non-regulated business development activities, and costs related to the Lambton GS and Nanticoke GS sites.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain PP&E and intangible assets held within Service, Trading, and Other Non-Generation segment. The total service fee is recorded as a reduction to the segment's OM&A expenses.

The service fee included in OM&A expenses by segment in 2017 and 2016 was as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| Regulated – Nuclear Generation | **36** | 34 |
| Regulated – Hydroelectric | **7** | 7 |
| Contracted Generation Portfolio | **4** | 4 |
| Reduction to Services, Trading, and Other Non-Generation | **47** | 45 |

## Fair Hydro Trust Segment

The Fair Hydro Trust segment is a non-generation segment that is not subject to rate regulation. It reports OPG's income related to its role as the Financial Services Manager under the Fair Hydro Act and holder of the Trust's subordinated debt, and includes the financial results of the Trust. Segment earnings include interest income from the Trust, recovery of third-party costs and fees for financial management and ongoing administration services, partially offset by interest costs on debt issued by OPG to fund its purchase of the Trust's subordinated debt and third-party and other costs incurred related to the management and administration of the Trust. OPG's fees for its services to the Trust, as the Financial Services Manager, are subject to an annual review by the OEB.

The earnings from the Fair Hydro Trust are comprised of the following for the year ended December 31:

| *(millions of dollars)* | **2017** |
|---|---|
| Revenue | **(8)** |
| Operating expenses | **8** |
| Interest income | **(1)** |
| Earnings from Fair Hydro Trust | **(1)** |

| Segment Income (Loss) for the Year Ended December 31, 2017 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Management | Hydro-Electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Fair Hydro Trust | Elimination | Total |
|---|---|---|---|---|---|---|---|---|
| Revenue | 3,095 | 121 | 1,436 | 579 | 43 | - | (116) | 5,158 |
| Fuel expense | 284 | - | 351 | 53 | 1 | - | - | 689 |
| Gross margin | 2,811 | 121 | 1,085 | 526 | 42 | - | (116) | 4,469 |
| Operations, maintenance and administration | 2,293 | 129 | 330 | 169 | 18 | 1 | (116) | 2,824 |
| Depreciation and amortization | 431 | - | 139 | 79 | 30 | - | - | 679 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 943 | - | 9 | 8 | - | - | 960 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (801) | - | - | - | - | - | (801) |
| Earnings from Fair Hydro Trust | - | - | - | - | - | (1) | - | (1) |
| Income from investments subject to significant influence | - | - | - | (38) | - | - | - | (38) |
| Property taxes | 26 | - | 1 | 7 | 6 | - | - | 40 |
| Other losses (gains) | 4 | - | 1 | - | (384) | - | - | (379) |
| Income (loss) before interest and income taxes | 57 | (150) | 614 | 300 | 364 | - | - | 1,185 |
| Net interest expense | | | | | | | | 95 |
| **Income before income taxes** | | | | | | | | 1,090 |
| Income tax expense | | | | | | | | 209 |
| **Net income** | | | | | | | | 881 |

| Segment Income (Loss) for the Year Ended December 31, 2016 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Management | Hydroelectric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Elimination | Total |
|---|---|---|---|---|---|---|---|
| Revenue | 3,481 | 138 | 1,527 | 573 | 68 | (134) | 5,653 |
| Fuel expense | 315 | - | 353 | 58 | 1 | - | 727 |
| Gross margin | 3,166 | 138 | 1,174 | 515 | 67 | (134) | 4,926 |
| Operations, maintenance and administration | 2,210 | 146 | 325 | 178 | 22 | (134) | 2,747 |
| Depreciation and amortization | 925 | - | 225 | 75 | 32 | - | 1,257 |
| Accretion on fixed asset removal and nuclear waste management liabilities | - | 912 | - | 9 | 8 | - | 929 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | - | (746) | - | - | - | - | (746) |
| Income from investments subject to significant influence | - | - | - | (37) | - | - | (37) |
| Property taxes | 26 | - | 1 | 7 | 12 | - | 46 |
| Restructuring | - | - | - | - | 6 | - | 6 |
| Other losses (gains) | 1 | - | (19) | 1 | - | - | (17) |
| Income (loss) before interest and income taxes | 4 | (174) | 642 | 282 | (13) | - | 741 |
| Net interest expense | | | | | | | 120 |
| **Income before income taxes** | | | | | | | 621 |
| Income tax expense | | | | | | | 168 |
| **Net income** | | | | | | | 453 |

| Selected Consolidated Balance Sheet information as at December 31, 2017<br>*(millions of dollars)* | Nuclear Gener-ation | Regulated Nuclear Waste Manage-ment | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Fair Hydro Trust | Total |
|---|---|---|---|---|---|---|---|
| Segment property, plant and equipment in-service, net | **6,167** | **-** | **7,359** | **3,480** | **224** | **-** | **17,230** |
| Segment construction in progress | **3,839** | **-** | **157** | **78** | **18** | **-** | **4,092** |
| Segment property, plant and equipment, net | **10,006** | **-** | **7,516** | **3,558** | **242** | **-** | **21,322** |
| Segment intangible assets in-service, net | **4** | **-** | **1** | **5** | **84** | **-** | **94** |
| Segment development in progress | **16** | **-** | **-** | **-** | **23** | **-** | **39** |
| Segment intangible assets, net | **20** | **-** | **1** | **5** | **107** | **-** | **133** |
| Segment fuel inventory | **265** | **-** | **-** | **44** | **-** | **-** | **309** |
| Segment materials and supplies inventory: | | | | | | | |
| Current | **102** | **-** | **-** | **1** | **-** | **-** | **103** |
| Long-term | **351** | **-** | **-** | **4** | **-** | **-** | **355** |
| Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions) | **-** | **16,724** | **-** | **-** | **-** | **-** | **16,724** |
| Financing receivables | **-** | **-** | **-** | **-** | **-** | **1,179** | **1,179** |
| Fixed asset removal and nuclear waste liabilities | **-** | **(20,077)** | **-** | **(151)** | **(193)** | **-** | **(20,421)** |

| Selected Consolidated Balance Sheet Information as at December 31, 2016 *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Management | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Total |
|---|---|---|---|---|---|---|
| Segment property, plant and equipment in-service, net | 5,653 | - | 7,355 | 3,282 | 226 | 16,516 |
| Segment construction in progress | 2,988 | - | 166 | 301 | 27 | 3,482 |
| Segment property, plant and equipment, net | 8,641 | - | 7,521 | 3,583 | 253 | 19,998 |
| Segment intangible assets in-service, net | 7 | - | 2 | 4 | 66 | 79 |
| Segment development in progress | 3 | - | - | 1 | 16 | 20 |
| Segment intangible assets, net | 10 | - | 2 | 5 | 82 | 99 |
| Segment fuel inventory | 276 | - | - | 34 | - | 310 |
| Segment materials and supplies inventory: | | | | | | |
| Current | 99 | - | - | 1 | - | 100 |
| Long-term | 340 | - | 1 | 4 | - | 345 |
| Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions) | - | 15,984 | - | - | - | 15,984 |
| Fixed asset removal and nuclear waste management liabilities | - | (19,103) | - | (160) | (221) | (19,484) |

| Segment Capital Expenditure Information *(millions of dollars)* | Nuclear Generation | Regulated Nuclear Waste Management | Hydro-electric | Unregulated Contracted Generation Portfolio | Unregulated Services, Trading, and Other Non-Generation | Fair Hydro Trust | Total |
|---|---|---|---|---|---|---|---|
| Year ended December 31, 2017 | | | | | | | |
| Investment in property, plant and equipment, and intangible assets | **1,631** | **-** | **148** | **73** | **74** | **-** | **1,926** |
| Year ended December 31, 2016 | | | | | | | |
| Investment in property, plant and equipment, and intangible assets | 1,338 | - | 132 | 198 | 36 | - | 1,704 |

## 18. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

| *(millions of dollars)* | December 31 2017 | 2016 |
|---|---|---|
| Receivables from related parties | **60** | 116 |
| Fuel inventory | **1** | 34 |
| Materials and supplies | **(3)** | (4) |
| Prepaid expenses | **(14)** | (6) |
| Other current assets [1] | **(28)** | (32) |
| Income taxes payable | **2** | 57 |
| Accounts payable and accrued charges | **36** | 15 |
| | **54** | 180 |

[1] Represents other accounts receivable.

## 19. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions for the years ended December 31 are summarized below:

| *(millions of dollars)* | 2017 Income | 2017 Expense | 2016 Income | 2016 Expense |
|---|---|---|---|---|
| Hydro One | | | | |
| Electricity sales | **8** | **-** | 6 | - |
| Services | **1** | **10** | 1 | 5 |
| Dividends | **7** | **-** | 6 | - |
| Province of Ontario | | | | |
| Change in Decommissioning Segregated Fund amount due to Province [1] | **-** | **456** | - | 192 |
| Change in Used Fuel Segregated Fund amount due to Province [1] | **-** | **591** | - | 235 |
| Hydroelectric gross revenue charge | **-** | **110** | - | 120 |
| ONFA guarantee fee | **-** | **8** | - | 8 |
| Other | **-** | **2** | - | - |
| OEFC | | | | |
| Hydroelectric gross revenue charge | **-** | **216** | - | 203 |
| Interest expense on long-term notes | **-** | **158** | - | 169 |
| Income taxes, net of investment tax credits | **-** | **246** | - | 104 |
| IESO | | | | |
| Electricity related revenue | **4,802** | **-** | 5,082 | - |
| Earnings from Fair Hydro Trust | **1** | **-** | - | - |
| | **4,819** | **1,797** | 5,095 | 1,036 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at December 31, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $4,462 million and $3,415 million, respectively.

The receivables, financing receivables, AFS securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| *(millions of dollars)* | December 31 2017 | 2016 |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO − Electricity related receivables | **354** | 421 |
| IESO − Fair Hydro Trust [1] | **7** | - |
| OEFC | **-** | 1 |
| PEC | **4** | 4 |
| Province of Ontario | **3** | 2 |
| Financing receivables | | |
| IESO − Fair Hydro Trust | **1,179** | - |
| Available-for-sale securities | | |
| Hydro One shares | **188** | 212 |
| Accounts payable and accrued charges | | |
| Hydro One | **1** | - |
| OEFC | **52** | 61 |
| Province of Ontario | **9** | 2 |
| IESO − Electricity related payables | **5** | 2 |
| IESO − Fair Hydro Trust | **3** | - |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,195** | 3,295 |

[1] Balance consists of unbilled revenue.

OPG may hold Province of Ontario bonds and treasury bills in the Nuclear Segregated Funds and the OPG registered pension fund. As at December 31, 2017, the Nuclear Segregated Funds held $1,502 million of Province of Ontario bonds (2016 − $1,650 million) and $9 million of Province of Ontario treasury bills (2016 − $2 million). As of December 31, 2017, the registered pension fund held $1 million in Province of Ontario treasury bills (2016 − $271 million). These Province of Ontario bonds and treasury bills are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

In December 2017, the Fair Hydro Trust purchased its first tranche of Investment Interest from the IESO for an exchange amount of $1.18 billion, which has been classified as a financing receivable on OPG's consolidated balance sheet. The transaction was settled in cash using proceeds from the Trust's issuance of senior debt to third parties and subordinated debt to OPG. Pursuant to the general regulation of the Fair Hydro Act, the IESO is required to pay and remit carrying costs of the Trust, excluding repayment of principal on any debt obligations, up to July 31, 2021. Commencing May 1, 2021, Specified Consumers will be invoiced by their local distribution company for the Clean Energy Adjustment to pay the carrying costs of the Trust. These funds will be remitted to the Trust through the IESO and will be used to settle all funding and other related expenses of the Trust that underlie the financing receivable.

As at December 31, 2017, OPG's consolidated balance sheet included approximately $7 million of unbilled revenue from the IESO, primarily for OPG's general fee for 2017 as the Financial Services Manager under the Act relating to incurred third-party and certain direct labour costs.

The Province has provided a limited guarantee to specified creditors of the Fair Hydro Trust. The limited guarantee would be triggered in the event that the Trust's ability to receive amounts in respect of its Investment Interest to pay for certain funding obligations is adversely affected due to one or more of the following: the Province changes the Fair Hydro Act or any other legislation or regulation; a significant change in Ontario's electricity market undertaken by the Province; or a court declares that the Act is invalid or unconstitutional.

## 20. INVESTMENTS SUBJECT TO SIGNIFICANT INFLUENCE

Investments subject to significant influence consist of OPG's 50 percent ownership interest in the jointly controlled entities of PEC and Brighton Beach, which are accounted for using the equity method. A summary of the balances of the jointly controlled entities as at December 31, 2017 and December 31, 2016 are as follows:

| *(millions of dollars)* | **2017** | **2016** |
|---|---|---|
| **PEC** | | |
| Current assets | **20** | 18 |
| Long-term assets | **240** | 256 |
| Current liabilities | **(10)** | (8) |
| Long-term liabilities | **(6)** | (5) |
| **Brighton Beach** | | |
| Current assets | **5** | 5 |
| Long-term assets | **160** | 168 |
| Current liabilities | **(17)** | (16) |
| Long-term liabilities | **(9)** | (7) |
| Long-term debt | **(74)** | (90) |
| Investments subject to significant influence | **309** | 321 |

## 21. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2017, research and development expenses of $106 million (2016 – $95 million) were charged to operations.

## 22. NON-CONTROLLING INTEREST

PSS Generating Station LP

PSS is a limited partnership between OPG, CRP and PSS GS Inc. The principal business of the partnership is the development, construction, ownership, operation and maintenance of the 28 MW Peter Sutherland Sr. hydroelectric GS on the New Post Creek.

The Peter Sutherland Sr. GS was placed in-service in March 2017 and, in April 2017, CRP increased its interest in PSS to 33 percent under the partnership agreement, by making contributions of $21 million, reducing OPG's interest to 67 percent. CRP's 33 percent interest in PSS is reported as non-controlling interest. As a result of CRP increasing its interest in the partnership, PSS's AOCL and partner's deficit as at the time of CRP's contribution were proportionately allocated to CRP as a reduction to its non-controlling interest.

Nanticoke Solar LP

In March 2016, Nanticoke Solar LP (NSLP), then a partnership between OPG, SunEdison Canadian Construction LP (SECCLP) and a subsidiary of the Six Nations of the Grand River Development Corporation, was selected through IESO's Large Renewal Procurement program to construct a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands. In the first quarter of 2017, OPG acquired all of SECCLP's interests in NSLP, which represented 25 percent of the equity interest in NSLP. Subsequent to the acquisition, OPG owns 90 percent of the equity interest in NSLP, with an approximate value of $2 million. OPG consolidates the results of the NSLP in its consolidated financial statements and reports the equity interest of the other partner as non-controlling interest.

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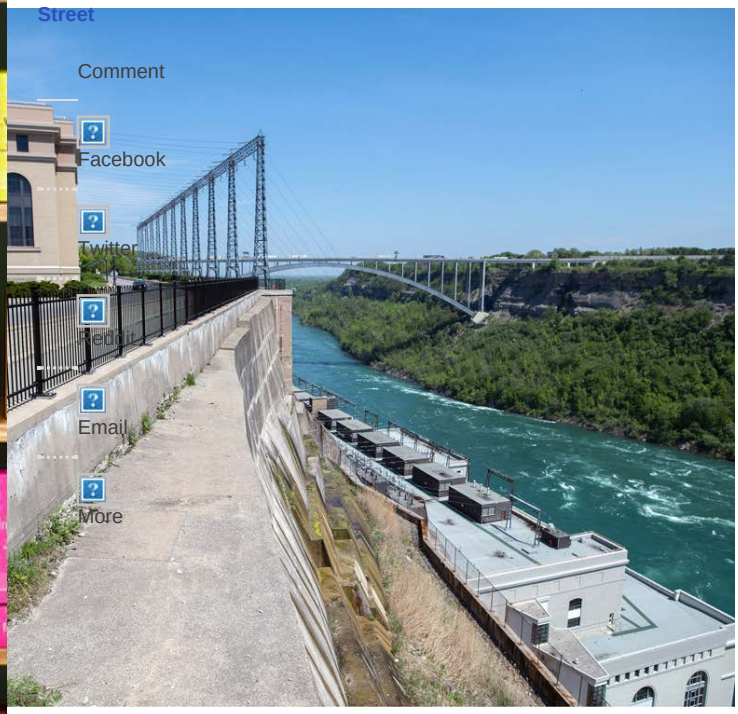
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OPG posted a green bond investor presentation

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ws past the offices, control centre, and lower river level turbine and
e Ontario Power Generation Sir Adam Beck Generating Station in Niagara
*MacDonald/Bloomberg*

The stage has been set for another issue of green bonds, the second in the past week.

This time around, Ontario Power Generation, an entity that is 100 per cent owned by the Ontario government

is set to come to the market, about a week after CPPIB, the investment manager for the country's public pension plan, raised $1.5 billion in its inaugural offering. That offering is also the largest by a Canadian issuer and the first by a pension fund.

On Monday, OPG posted a green bond investor presentation on SEDAR. The amount the issuer intends to raise wasn't disclosed but the marketing materials indicated that there is $528 million of capital expenditure indicated as eligible hydro projects. Of that amount, $311 million is what has been spent over the past two years while the balance ($217 million) is projected for 2018. Eligible projects are defined as those that focus on renewable energy generation and which aid energy efficiency and management.

## SEE ALSO

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'Bumbling mismanagement': Ontario Fair Hydro bonds offer juicy yield and hefty political baggage

Behind Manulife's historic $600 million green bond issue: first for an insurer in domestic market

OPG has gone the extra mile to get its upcoming green bond certified: it hired Sustainalytics for a second opinion. The research firm signed off by noting that OPG's green bond framework "is credible and




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impactful and aligns with the four core principles of the Green Bond Principles 2017." It based that assessment on the use of proceeds (the projects selected will have "clear positive environmental impacts,"); on project evaluation and selection; on management of the proceeds; and on reporting (OPG will report annually on how the proceeds are allocated).

OPG, which is Ontario's largest clean energy generator, owns 72-generation facilities, of which 66 are hydro and two are nuclear. In those marketing materials, it said that following the closing of its coal-fired generation plants, 99 per cent of the power it produces is "free of smog and greenhouse gas emissions."

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If and when it issues green bonds, it will mark its second domestic bond offering: last October it raised $500 million of 10-year money at a coupon of 3.315 per cent. In September 2017, it established a $2 billion medium term note program.

BMO Capital Markets and TD Securities have been chosen as the lead bookrunners. OPG has a split rating: DBRS has assigned an A (low) rating while S&P has assigned a BBB+ rating.

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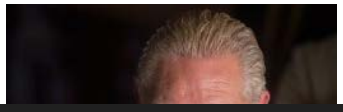
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ONTARIO POWER GENERATION

January 30, 2018

Shruti Talwar
Director, Strategic Policy and Analytics Branch
Strategic, Network and Agency Policy Division
Ontario Ministry of Energy

**Draft fiscal values for OPG's 2018-2021 Business Plan**

Attached please find the values for OPG's draft business plan, converted to the Province's fiscal calendar, on a US GAAP basis. The plan reflects the impacts from the OEB Decision announced on December 28, 2017. Given the timing of the Decision, the business plan is being tabled and approved by the OPG Board on Feb 12, 2018. The concurrence process through the Treasury Board Secretariat will immediately follow OPG's Board approval of the Business Plan. Until such time as the OPG Board approves the 2018 – 2021 Business Plan, the values as attached that accumulate to Total Shareholder Return, should be considered draft or preliminary.

Thank-you

John Mauti
Chief Controller & Accounting Officer
Ontario Power Generation Inc.

Cc: Jeff Lyash
Ken Hartwick
Catriona King

| OPG- 2018-2021 Forecast | | | | |
|---|---|---|---|---|
| | | Province's March 31 Fiscal Year | | |
| | Forecast | Preliminary 2018-2021 BP | | |
| *$ millions* | 2018 * | 2019 | 2020 | 2021 |
| **Net Income Attributable to Shareholder** | **1,184** | **791** | **1,051** | **874** |
| **Non Income Tax PILs** | | | | |
| GRC: Payable to OEFC | 206 | 209 | 212 | 212 |
| GRC: Payable to MOF | 103 | 101 | 103 | 103 |
| GRC: Payable to Niagara Parks Commission | 7 | 7 | 7 | 8 |
| Property Tax Payable to OEFC | 13 | 14 | 14 | 13 |
| **Total** | **330** | **331** | **336** | **335** |
| **Income Tax PILs** | 216 | 58 | 177 | 171 |
| **Total Shareholder Return **** | **1,730** | **1,180** | **1,564** | **1,381** |

* Includes Gain from Sale of 700 University (EBT $376M; Net Income $283M), and an estimate of the Sale of Lakeview (EBT ~$250M; Net Income ~$185M)

** Excludes EBT from Fair Hydro Plan of $15M, $80M, $150M and $225M for fiscal years ended March 31, 2018-2021

# ONTARIO POWER GENERATION INC.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

## 2017 THIRD QUARTER REPORT

## [DRAFT]

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ONTARIO POWER GENERATION

# ONTARIO POWER GENERATION INC.
# MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis (MD&A) should be read in conjunction with the unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine months ended September 30, 2017. OPG's unaudited interim consolidated financial statements are prepared in accordance with United States generally accepted accounting principles (US GAAP) and are presented in Canadian dollars.

For a complete description of OPG's corporate strategies, risk management, corporate governance, and the effect of critical accounting policies and estimates on OPG's results of operations and financial condition, this MD&A should also be read in conjunction with OPG's audited consolidated financial statements, accompanying notes, the Annual Information Form, and the MD&A as at and for the year ended December 31, 2016.

As required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), OPG adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. In 2014, the Ontario Securities Commission approved an exemption which allows OPG to apply US GAAP up to January 1, 2019. The term of the exemption is subject to certain conditions, which may result in the expiry of the exemption prior to January 1, 2019. For details, refer to the section, *Critical Accounting Policies and Estimates* under the heading, *Exemptive Relief for Reporting under US GAAP,* in OPG's 2016 annual MD&A. This MD&A is dated November 9, 2017.

## FORWARD-LOOKING STATEMENTS

The MD&A contains forward-looking statements that reflect OPG's current views regarding certain future events and circumstances. Any statement contained in this document that is not current or historical is a forward-looking statement. OPG generally uses words such as "anticipate", "believe", "foresee", "forecast", "estimate", "expect", "schedule", "intend", "plan", "project", "seek", "target", "goal", "strategy", "may", "will", "should", "could", and other similar words and expressions to indicate forward-looking statements. The absence of any such word or expression does not indicate that a statement is not forward-looking.

All forward-looking statements involve inherent assumptions, risks, and uncertainties, including those set out in the section, *Risk Management,* and forecasts discussed in the section, *Core Business, Strategy, and Outlook.* All forward-looking statements could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's generating station performance and availability, fuel costs, surplus baseload generation (SBG), cost of fixed asset removal and nuclear waste management, performance and earnings of investment funds, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations and funds, income taxes, proposed new legislation, the ongoing evolution of Ontario's electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, financing and liquidity, applications to the Ontario Energy Board (OEB) for regulatory prices, the impact of regulatory decisions by the OEB, and forecasts of earnings, cash flows, Funds from Operations (FFO) Adjusted Interest Coverage, Return on Common Equity Excluding Accumulated Other Comprehensive Income (ROE Excluding AOCI), Total Generating Cost (TGC) and capital expenditures. Accordingly, undue reliance should not be placed on any forward-looking statement. The forward-looking statements included in this MD&A are made only as of the date of this MD&A. Except as required by applicable securities laws, OPG does not undertake to publicly update these forward-looking statements to reflect new information, future events, or otherwise.

## THE COMPANY

OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG was established under the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (Province or Shareholder).

As at September 30, 2017, OPG's electricity generation portfolio had an in-service capacity of 16,210 megawatts (MW). OPG operates two nuclear generating stations, 66 hydroelectric generating stations, three thermal generating stations, and one wind power turbine. In addition, OPG and TransCanada Energy Ltd. co-own the 550 MW Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the 560 MW Brighton Beach gas-fired combined cycle GS (Brighton Beach). OPG's 50 percent share of the in-service capacity and generation volume of these co-owned facilities is included in the generation portfolio statistics set out in this report. The income from the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented as income from investments subject to significant influence in the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, the Bruce A GS and the Bruce B GS, which are leased on a long-term basis to Bruce Power LP (Bruce Power). Income from these leased stations is included in revenue under the Regulated – Nuclear Generation segment. The leased stations are not included in the generation portfolio statistics set out in this report.

All of OPG's owned and co-owned generating facilities are located in Ontario. OPG does not operate PEC, Brighton Beach, the Bruce A GS and the Bruce B GS.

A description of OPG's segments is provided in OPG's 2016 annual MD&A in the section, *Business Segments*.

### In-Service Generating Capacity

OPG's in-service generating capacity by business segment as at September 30, 2017 and December 31, 2016 was as follows:

| | As at | |
|---|---|---|
| *(MW)* | **September 30 2017** | **December 31 2016** |
| Regulated – Nuclear Generation [1] | **5,728** | 5,728 |
| Regulated – Hydroelectric | **6,426** | 6,421 |
| Contracted Generation Portfolio [2] | **4,056** | 4,028 |
| Total | **16,210** | 16,177 |

[1] The in-service generating capacity as of September 30, 2017 and December 31, 2016 excludes Unit 2 of the Darlington GS. The unit, which has a generating capacity of 878 MW, was taken offline in mid-October 2016 and is currently undergoing refurbishment.

[2] Includes OPG's share of in-service generating capacity of 275 MW for PEC and 280 MW for Brighton Beach.

During the nine months ended September 30, 2017, the total in-service capacity increased by 33 MW. The increase was primarily due to the completion of the Peter Sutherland Sr. hydroelectric GS, which was placed in-service at the end of the first quarter of 2017, and the upgrade of Unit 10 of the Sir Adam Beck 1 hydroelectric GS, which was completed in June 2017.

## HIGHLIGHTS

### Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. Significant factors which contributed to OPG's results during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, are discussed below.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Revenue | **1,217** | 1,400 | **3,539** | 4,265 |
| Fuel expense | **185** | 187 | **518** | 541 |
| Gross margin | **1,032** | 1,213 | **3,021** | 3,724 |
| Operations, maintenance and administration | **635** | 666 | **2,054** | 2,061 |
| Depreciation and amortization | **178** | 313 | **517** | 941 |
| Accretion on fixed asset removal and nuclear waste management liabilities | **235** | 232 | **709** | 696 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(196)** | (248) | **(579)** | (620) |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| Property taxes | **8** | 12 | **30** | 35 |
| | **849** | 964 | **2,702** | 3,085 |
| Income before other losses (gains), interest and income taxes | **183** | 249 | **319** | 639 |
| Other losses (gains) | **3** | 1 | **(380)** | (23) |
| Income before interest and income taxes | **180** | 248 | **699** | 662 |
| Net interest expense | **21** | 28 | **56** | 92 |
| Income before income taxes | **159** | 220 | **643** | 570 |
| Income tax expense | **19** | 22 | **128** | 109 |
| Net income | **140** | 198 | **515** | 461 |
| Net income attributable to the Shareholder | **131** | 194 | **498** | 449 |
| Net income attributable to non-controlling interest [1] | **9** | 4 | **17** | 12 |
| *Electricity production (TWh)* [2] | **19.4** | 19.5 | **56.0** | 59.9 |
| *Cash flow provided by operating activities* | **485** | 530 | **698** | 1,211 |

[1] Relates to the 25 percent interest of the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, in the Lower Mattagami Limited Partnership, the 33 percent interest of Coral Rapids Power Corporation, a corporation wholly owned by the Taykwa Tagamou Nation, in the PSS Generating Station Limited Partnership, and the 10 percent interest of a corporation wholly owned by the Six Nations of Grand River Development Corporation in the Nanticoke Solar LP.

[2] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder was $131 million for the third quarter of 2017, a decrease of $63 million compared to the same quarter in 2016. Income before interest and income taxes for the third quarter of 2017 was $180 million, a decrease of $68 million compared to the same quarter in 2016.

**Commented [A1]:**
Wondering if this should be 437?
Since:
Q3 9-mos ended – Q2 6-mos ended = 698-261 = 437

Was Q2 "6-month ended June 30" number for Cash flow provided by operating activities revised?

OPG: In Q3 2017, adjustments for non-cash balances related to Darlington Refurbishment capital expenditures have been reclassified from the "Net changes in non-cash working capital balances" line to the "Investment in property, plant and equipment and intangible assets" line. Comparative amounts have been reclassified accordingly.

*Significant factors that reduced income before interest and income taxes:*

- Lower earnings from the nuclear base regulated price of approximately $24 million reflecting lower electricity generation of 0.4 terawatt hours (TWh) from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS since October 2016, largely offset by an increase in generation from Pickering GS. The increase in generation from the Pickering GS was primarily due to outage optimization, favourable unit conditions and execution of planned outage work. The base regulated prices set in 2014 continue to be in effect pending the OEB's decision on OPG's current application for new regulated prices, expected later in 2017. **[MONITOR]** The existing nuclear base regulated price was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. OPG has requested January 1, 2017 as the effective date of the new regulated prices.
- Lower earnings on the nuclear fixed asset removal and nuclear waste management funds (Nuclear Segregated Funds) of $52 million.
- Higher depreciation and amortization expense of $16 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to balances in OEB-authorized regulatory variance and deferral accounts (regulatory accounts), primarily due to new assets in service.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the three months ended September 30, 2017, compared to the same period in 2016, but was largely offset by a decrease in the amortization expense related to these balances. OPG has requested new rate riders in its current application to the OEB for new regulated prices, with a proposed effective date of January 1, 2017.

*Significant factor that increased income before interest and income taxes:*

- Lower operations, maintenance and administration (OM&A) expenses of $31 million, mainly in the Regulated – Nuclear Generation segment, as a result of a higher materials and supplies obsolescence charge recognized in the third quarter of 2016, Services, Trading and Other Non-Generation segment due to project expenditures incurred in the third quarter of 2016, and Regulated – Hydroelectric segment due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

Net interest expense decreased by $7 million during the third quarter of 2017, compared to the same quarter in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

Income tax expense for the three months ended September 30, 2017 was $19 million, compared to $22 million for the same period in 2016. The decrease in income tax expense was primarily due to lower income before taxes and a higher change in reserves from the resolution of uncertainties, partially offset by a lower amount of tax expense deferred in regulatory assets.

Year-To-Date

Net income attributable to the Shareholder was $498 million for the first nine months of 2017, an increase of $49 million compared to the same period in 2016. Income before interest and income taxes for the first nine months of 2017 was $699 million, an increase of $37 million compared to the same period in 2016.

*Significant factor that increased income before interest and income taxes:*

- Higher earnings of $390 million from the Services, Trading, and Other Non-Generation segment, primarily reflecting the gain on sale of OPG's head office premises and associated parking facility located at 700 University Avenue and 40 Murray Street that was recognized in the second quarter of 2017. The sale of the

**Commented [A2]:** If approved by OEB (during Q4), would this result in a higher regulated price and a revenue/net income pick up for 2017 reported in OPG's Q4?

OPG – It depends on the effective date of the decision on the base regulated prices. If the OEB decision on the new base regulated prices are retrospectively effective as of Jan 1, 2017 for example, then it should result in a higher revenue/net income pick up for 2017 assuming the new regulated prices are higher.

assets was required by a Shareholder Declaration and a Shareholder Resolution. The gain on sale was $283 million, which is net of tax effects of $95 million.

*Significant factors that reduced income before interest and income taxes:*

- Lower earnings from the nuclear base regulated price of approximately $230 million, partially offset by a decrease in nuclear fuel expense of $22 million, reflecting lower electricity generation of 4.0 TWh from the Regulated – Nuclear Generation segment and the continuation of existing base regulated prices set by the OEB in 2014. The lower nuclear generation was primarily due to the ongoing refurbishment of Unit 2 at the Darlington GS, partially offset by an increase in generation from Pickering GS.
- Lower earnings on the Nuclear Segregated Funds of $41 million.
- Higher depreciation and amortization expense of $30 million in the Regulated – Nuclear Generation segment, excluding amortization expense related to regulatory account balances, primarily due to new assets in service.
- A gain of $22 million recorded in the first quarter of 2016 to reflect the OEB's decision on OPG's motion asking the OEB to review and vary parts of its November 2014 decision on OPG's regulated prices.

The expiry of rate riders for the recovery of approved balances in OEB-authorized regulatory accounts on December 31, 2016 contributed to the decrease in revenue for the nine months ended September 30, 2017, compared to the same period in 2016, but was primarily offset by a decrease in the amortization expense related to these balances.

Net interest expense decreased by $36 million for the nine months ended September 30, 2017, compared to the same period in 2016, primarily due to a higher amount of interest costs capitalized for the Darlington Refurbishment project expenditures and a higher amount of interest costs deferred in OEB-authorized regulatory accounts.

**Commented [A3]:** Does this imply there were interest costs related to Darlington Refurb previously (same quarter previous year), that were not capitalized, but were able to be capitalized this year?

OPG – There were higher Darlington Refurb project expenditures in 2017, compared to 2016.

Income tax expense for the nine months ended September 30, 2017 was $128 million, compared to $109 million for the same period in 2016. The increase in income tax expense was primarily due to higher income before income taxes.

## Segment Results

The following table summarizes OPG's income before interest and income taxes by business segment. A detailed discussion of OPG's performance by reportable segment is included in the section, *Discussion of Operating Results by Business Segment*.

| *(millions of dollars)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| *Income (loss) before interest and income taxes* | | | | |
| Regulated – Nuclear Generation | **20** | 47 | **(267)** | 17 |
| Regulated – Hydroelectric | **122** | 117 | **474** | 500 |
| Contracted Generation Portfolio | **75** | 74 | **229** | 219 |
| Total electricity generation business segments | **217** | 238 | **436** | 736 |
| Regulated – Nuclear Waste Management | **(36)** | 18 | **(123)** | (70) |
| Services, Trading, and Other Non-Generation | **(1)** | (8) | **386** | (4) |
| | **180** | 248 | **699** | 662 |

## Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2017 and 2016 was as follows:

| *(TWh)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Regulated – Nuclear Generation | **11.3** | 11.7 | **30.6** | 34.6 |
| Regulated – Hydroelectric | **7.3** | 6.9 | **23.5** | 22.8 |
| Contracted Generation Portfolio [1] | **0.8** | 0.9 | **1.9** | 2.5 |
| Total OPG electricity generation | **19.4** | 19.5 | **56.0** | 59.9 |
| Total electricity generation by all other generators in Ontario [2] | **16.6** | 19.5 | **51.7** | 53.8 |

[1] Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.
[2] Non-OPG generation is calculated as the Ontario electricity demand plus net exports, as published by the Independent Electricity System Operator (IESO), minus OPG electricity generation.

Total OPG electricity generation decreased by 0.1 TWh during the third quarter of 2017, compared to the same quarter in 2016, and by 3.9 TWh during the nine months ended September 30, 2017, compared to the same period in 2016. As expected, the lower electricity generation from the Regulated – Nuclear Generation segment was primarily the result of the removal from service of Unit 2 at the Darlington GS for the duration of the unit's refurbishment, which began in October 2016. This decrease in electricity generation was largely offset by an increase in generation from the Pickering GS, primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station, and higher hydroelectric generation from the Regulated – Hydroelectric segment.

The higher electricity generation of 0.4 TWh and 0.7 TWh from the Regulated – Hydroelectric segment for the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, was due to higher water flows primarily on the eastern Ontario river systems, net of water spilled as a result of SBG conditions, discussed below.

The lower electricity generation of 0.6 TWh from the Contracted Generation Portfolio segment for the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to higher SBG conditions. The electricity generation from the Contracted Generation Portfolio segment for the three months ended September 30, 2017 was comparable to the same period in 2016.

OPG's operating results are impacted by changes in grid-supplied electricity demand resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. For the three and nine month periods ended September 30, 2017, Ontario's electricity demand as reported by the IESO was 33.6 TWh and 98.5 TWh, respectively, compared to 36.7 TWh and 103.8 TWh for the same periods in 2016, respectively, excluding electricity exports out of the province.

Power that is surplus to the Ontario market is managed by the IESO, mainly through generation reductions at hydroelectric, other grid-connected renewable resources and nuclear stations. Reducing hydroelectric production is the first measure used by the IESO to manage SBG conditions. Low demand conditions in Ontario continued to be prevalent in 2017, resulting in forgone hydroelectric generation for OPG of 1.1 TWh and 4.5 TWh due to SBG conditions in the three and nine month periods ended September 30, 2017, respectively, compared to 0.5 TWh and 3.9 TWh during the same periods in 2016, respectively. The gross margin impact of production forgone at OPG's regulated hydroelectric stations due to SBG conditions during these periods was offset by the impact of a regulatory variance account authorized by the OEB. OPG did not forgo any electricity production at its nuclear stations due to SBG conditions.

### Average Sales Prices

The majority of OPG's generation is from the Regulated – Nuclear Generation and Regulated – Hydroelectric segments. The same base regulated prices for electricity generated by these segments, authorized by the OEB effective November 1, 2014, were in effect during the first nine months of 2017 as in 2016. These prices will remain in effect until such time as the OEB approves new regulated prices based on OPG's current application. **[MONITOR]** The base regulated prices established in 2014 are discussed in OPG's 2016 annual MD&A in the section, *Revenue Mechanisms for Regulated and Non-Regulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment was 5.8 cents per kilowatt hour (¢/kWh) during the three and nine month periods ended September 30, 2017, respectively, compared to 6.9 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized nuclear rate rider of $10.84 per megawatt hour (MWh) for the recovery of variance and deferral account balances. The average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh during the three and nine month periods ended September 30, 2017, respectively, compared to 4.4 ¢/kWh during the same periods in 2016. The decrease in the average sales price was primarily due to the expiry, on December 31, 2016, of an OEB-authorized regulated hydroelectric rate rider of $3.19/MWh for the recovery of variance and deferral account balances. The rate riders were established to recover approved balances recorded in the variance and deferral accounts in prior years. As such, the year-over-year changes in revenue from the rate riders were largely offset by changes in amortization expense related to these balances. There were no rate riders in effect during the nine months ended September 30, 2017 for either nuclear or regulated hydroelectric generation, pending the outcome of OPG's current application with the OEB for new regulated prices.

### Cash Flow from Operations

Cash flow provided by operating activities was $485 million for the three months ended September 30, 2017 and $698 million for the nine months ended September 30, 2017, compared to $530 million and $1,211 million for the same periods in 2016, respectively. The decrease in cash flow provided by operating activities was expected and primarily due to lower generation revenue receipts reflecting lower generation from the Regulated – Nuclear Generation segment as a result of the ongoing refurbishment of Unit 2 at the Darlington GS and the expiry, on December 31, 2016, of the OEB-authorized rate riders for nuclear and regulated hydroelectric generation. The decrease in cash flow during the nine months ended September 30, 2017 was also due to higher income tax instalments.

The decrease in cash flow provided by operating activities for the three and nine month periods ended September 30, 2017 was partly offset by lower OM&A expenditures and lower contributions to the Used Fuel Segregated Fund in 2017. Both the Used Fuel Segregated Fund and the Decommissioning Segregated Fund were determined to be fully funded based on an updated estimate of OPG's nuclear waste management and nuclear facilities decommissioning obligations pursuant to a reference plan approved by the Province ~~for years 2017 to 2021~~ under the Ontario Nuclear Funds Agreement (ONFA), effective January 1, 2017. Pursuant to the ONFA, the reference plan is required to be updated at least once every five years. Contributions to either or both of the Nuclear Segregated Funds may be required in the future should the funds be in an underfunded position at the time of the next ONFA reference plan update. The year-over-year decrease in cash flow also was partially offset by the payment of a supplemental rent rebate to Bruce Power in the first quarter of 2016 in relation to a period in 2015. The lease agreement for the Bruce nuclear generating stations was amended in late 2015 to eliminate this rebate provision going forward.

**Commented [A4]:** OPG: no change as this was previously disclosed as is in Q2 2017.

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### Return on Common Equity Excluding Accumulated Other Comprehensive Income

ROE Excluding AOCI is an indicator of OPG's performance consistent with the Company's strategy to provide value to the Shareholder. ROE Excluding AOCI is measured over a 12-month period.

ROE Excluding AOCI was 4.4 percent for the 12 months ended September 30, 2017, compared to 4.2 percent for the 12 months ended December 31, 2016. The increase was primarily due to higher net income attributable to the Shareholder for the 12 months ended September 30, 2017, which reflected the gain on sale of OPG's head office premises and associated parking facility recorded in the second quarter of 2017, partially offset by the lower earnings from the decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS without a corresponding increase in the nuclear base regulated price, as expected. The lower nuclear generation as a result of the refurbishment outage will continue to negatively affect OPG's ROE Excluding AOCI until such time as new regulated prices are approved by the OEB, anticipated in the fourth quarter of 2017. **[MONITOR]**

### Funds from Operations Adjusted Interest Coverage

FFO Adjusted Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. The indicator is measured over a 12-month period. FFO Adjusted Interest Coverage for the 12 months ended September 30, 2017 was 4.2 times, compared to 5.1 times for the 12 months ended December 31, 2016. FFO Adjusted Interest Coverage in 2017 reflected a year-over-year decrease in FFO before interest due to lower cash flow provided by operating activities, partially offset by the impact of a lower adjusted interest expense due to a decrease in the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets.

The decrease in the excess of interest on pension and OPEB benefit obligations over expected return on pension plan assets in the nine months of 2017 was primarily due to the change in the method used to estimate the interest cost and service cost components of pension and OPEB costs. Effective January 1, 2017, OPG adopted a full yield curve approach to the estimation of these cost components, by applying the specific spot rates along the yield curve used in the determination of the projected benefit obligations to the relevant projected cash flows. Under the previous method, these components of pension and OPEB costs were calculated using the same single weighted-average discount rates as reflected in the calculation of the benefit obligations. This change in the method was accounted for prospectively, as a change in estimate. The resulting reduction in pension and OPEB costs for the three and nine month periods ended September 30, 2017 did not have a material impact on net income as it was largely offset by the impact of OEB-authorized variance and deferral accounts in the regulated business segments. Further details on the full yield curve approach can be found in the 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Pension and Other Post-Employment Benefits*.

**Commented [A5]:** Does this have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts?

OPG response - Since the full yield curve approach is applied to the determination of pension and OPEB costs under both US GAAP and IFRS, it will not create a US GAAP and IFRS difference. Therefore it is not expected to have any implications for the methodology used for the IFRS adjustments for the purposes of the Province's Public Accounts.

### Enterprise Total Generating Cost per MWh

The Enterprise TGC per MWh decreased to $46.65 for the three months ended September 30, 2017, compared to $50.72 for the same quarter in 2016. The decrease was mainly due to lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

The Enterprise TGC per MWh was $47.77 for the nine months ended September 30, 2017, an increase compared to $46.74 for the same period in 2016. The increase was expected and mainly a result of lower electricity generation due to the Unit 2 refurbishment outage at the Darlington GS, largely offset by lower OM&A expenses before the impact of regulatory accounts and higher SBG-adjusted hydroelectric generation reflecting higher water flows.

If Unit 2 at the Darlington GS was not currently undergoing refurbishment and had continued to operate in a manner consistent with the performance of the remaining units at the Darlington GS, adjusting for generation constraints on these units related to the transition of the station toward refurbishment, the Enterprise TGC would have been approximately $4 per MWh lower for both the three and nine month periods ended September 30, 2017. This sensitivity was calculated using the estimated incremental electricity and associated fuel cost that are expected to have resulted in the absence of the refurbishment.

### Nuclear Total Generating Cost per MWh

The Nuclear TGC per MWh was $58.75 for the three months ended September 30, 2017, which was comparable to $58.55 for the same quarter in 2016. For the three months ended September 30, 2017, the higher generation at the Pickering GS and the impact of lower OM&A expenses before the impact of regulatory accounts was mostly offset by the expected decrease in nuclear electricity generation reflecting the Unit 2 refurbishment outage at the Darlington GS and higher sustaining capital expenditures. The Nuclear TGC per MWh was $67.87 for the nine months ended September 30, 2017, compared to $61.07 for the same period in 2016. The increase in the Nuclear TGC per MWh for the nine months ended September 30, 2017 was expected and primarily due to the decrease in nuclear electricity generation, partially offset by lower OM&A expenses before the impact of regulatory accounts.

### Hydroelectric Total Generating Cost per MWh

The Hydroelectric TGC per MWh was $26.20 for the three months ended September 30, 2017, compared to $31.01 for the same quarter in 2016. The decrease was primarily due to higher SBG-adjusted hydroelectric electricity generation reflecting higher water flows. The Hydroelectric TGC per MWh was $21.74 for the nine months ended September 30, 2017, compared to $23.99 for the same period in 2016. The decrease was primarily due to lower OM&A expenses before the impact of regulatory accounts and lower sustaining capital expenditures.

ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are not measurements in accordance with US GAAP and should not be considered alternative measures to net income, cash flow provided by operating activities, or any other performance measure under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the Company's strategic imperatives and related objectives. The definition and calculation of ROE Excluding AOCI, FFO Adjusted Interest Coverage, Enterprise TGC per MWh, Nuclear TGC per MWh and Hydroelectric TGC per MWh are found in the section, *Supplementary Non-GAAP Financial Measures*.

### Recent Developments

Ontario's 2017 Long Term Energy Plan

On October 26, 2017, Ontario's Ministry of Energy issued the 2017 Long Term Energy Plan. The Plan is currently being analyzed by OPG but is not expected to significantly impact OPG's business. There are no fundamental changes from the principles in the 2013 Long Term Energy Plan, which include cost effectiveness, reliability, clean energy and community engagement. The 2017 Long Term Energy Plan fully supports nuclear refurbishment projects in Ontario and the extension of commercial operation of all Pickering units to 2024. **[MONITOR & UPDATE DETAILS FOLLOWING RELEASE]**

OEB's Decision on New Regulated Prices **[MONITOR]**

Ontario's Fair Hydro Plan

OPG continues to prepare for its involvement as the Financial Services Manager for Ontario's Fair Hydro Plan (the Fair Hydro Plan) on a commercial basis. Accordingly, the financing entity was established in XX 2017 as the Fair Hydro Trust (the Trust), following the execution of its constating documents. The majority unitholder and beneficiary of the Trust is a wholly-owned subsidiary of OPG. Through this ownership and OPG's control over the key activities of the Trust, the Company will consolidate the Trust for accounting purposes commencing in the fourth quarter of 2017. **[MONITOR]**

In order for the Trust to provide financing for the deferred Global Adjustment costs, the Trust will incur senior debt from capital markets and subordinated debt from OPG. The Trust is structured to be bankruptcy remote and ring fenced from OPG to protect the Company's assets and operations. In support of the Fair Hydro Plan, the following developments have transpired:

**Commented [A6]:** Why not rephrase as acquiring the investment asset related to the deferred GA costs (right to future recovery)?

OPG response: No change made.

It is easier to understand for the general public the notion of a financing transaction vs. acquiring an investment interest

- In October 2017, *Ontario Regulation 206/17 General* was amended to establish details of the recovery mechanism for the monthly carrying costs incurred by the Trust from June 1, 2017 to July 31, 2021 payable by the IESO to the Trust. Originally established in June 2017, this regulation provides more details on the funding obligations incurred by the Trust and the fair allocation amount, the determination and collection of clean energy adjustments, the determination of the finance amount, the true up amount, and the regulatory asset, as well as principles and assumptions relating to the financing plan.
- A plan to amend the Company's Articles of Amalgamation to allow for the creation and issuance of Class A shares to be issued to the Province for its equity investment through OPG in the Fair Hydro Plan is in progress. The Province is expected to provide 44 percent of the total funding requirement related to the deferred Global Adjustment costs, which OPG will invest as subordinated debt into the Trust. OPG's Board approval and a Shareholder Resolution are expected later in the year to authorize the amendment.
- OPG is expected to provide five percent of the total funding requirement of the Trust related to the deferred Global Adjustment costs of the Fair Hydro Plan. OPG issued senior notes payable in October 2017 under a short form base shelf prospectus for general corporate purposes and to fund OPG's subordinated debt investment in the Trust. Further details of the debt offering can be found in the section, *Liquidity and Capital Resources* under the heading, *Financing Activities*.

**Commented [A7]:** Are any other details available to be released at this time?

OPG – Not for Q3 2017 reporting.

The first set of transactions of the Trust are expected to take place in the fourth quarter of 2017.

Canadian Nuclear Safety Commission Safety Rating for the Darlington GS and the Pickering GS

The Canadian Nuclear Safety Commission (CNSC) publishes an annual report on the safety performance of Canada's nuclear power plants. The report assesses how well plant operators are meeting regulatory requirements and program expectations in the areas of operational performance, safety analysis, radiation protection, waste management and conventional health and safety. On September 8, 2017, the CNSC issued an executive summary of its 2016 annual report. The CNSC gave both the Darlington GS and the Pickering GS the highest possible safety rating of "Fully Satisfactory". The Darlington GS achieved this rating for the eighth consecutive year, while the Pickering GS achieved this rating for the second consecutive year.

## CORE BUSINESS, STRATEGY, AND OUTLOOK

The discussion in this section is qualified in its entirety by the cautionary statements included in the section, *Forward-Looking Statements,* at the beginning of the MD&A.

OPG's mission is to provide low cost power in a safe, clean, reliable and sustainable manner for the benefit of customers and its Shareholder. OPG also seeks to pursue, on a commercial basis, generation development projects and other business growth opportunities.

The following sections provide an update to OPG's disclosures in the 2016 annual MD&A related to its four key strategic imperatives – operational excellence, project excellence, financial strength, and social licence. A detailed discussion of these strategic imperatives is included in the 2016 annual MD&A in the section, *Core Business, Strategy, and Outlook*.

### Operational Excellence

Operational excellence at OPG is accomplished by the safe and environmentally responsible generation of reliable and cost-effective electricity from the Company's generating assets through a highly trained and engaged workforce.

Electricity Generation Production and Reliability

- As part of the plan to extend Pickering operations, OPG is continuing to undertake the required technical work to confirm that the station's pressure tubes, a key life-limiting component of the station, will remain fit for service for operation to 2024. OPG is also nearing completion of component condition assessments to identify the work required to support the continued operation of the station. The accounting end of life assumptions for the Pickering GS, currently set at the end of 2020, will be reassessed based on the fuel channel analysis and safety case consistent with submissions for the CNSC approval, discussed below. The activities completed to date have had positive results, which will go towards re-confirming Pickering operations past 2020 are technically feasible. The Periodic Safety Review (PSR) is in progress and will confirm that extending operations of the Pickering units will be safe to the public, workers and the environment. The PSR consists of Safety Factor Reports (SFRs), a Global Assessment Report (GAR), and the Integration Improvement Plan (IIP). SFRs have been submitted to the CNSC and the GAR and IIP are on track for CNSC submission in October and November 2017, respectively. Other technical feasibility activities continue to progress as planned. Completion of various technical feasibility assessments are required to reach a high confidence conclusion to allow the station end of life to change for depreciation purposes. OPG's current application with the OEB for new base regulated prices, currently pending the OEB's decision, reflects OPG's plans to extend Pickering operations to 2024 and requests inclusion of the corresponding cost and generation impacts in the determination of the nuclear regulated price.
- OPG's current five-year operating licence for the Pickering GS was approved by the CNSC in 2013 and expires on August 31, 2018. This licence was issued assuming that the station would shut down in 2020. On June 28, 2017, OPG confirmed to the CNSC that it intends to cease commercial operation of all Pickering units on December 31, 2024. On August 28, 2017, OPG submitted a ten-year licence renewal application to the CNSC. The licence term spans the planned extended operations period, through to the end of commercial operation, defueling, dewatering and the start of placing the station in a safe storage state.
- Work continues on the rehabilitation of Unit 2 of the DeCew Falls hydroelectric GS and the rehabilitation and overhaul of Unit 2 of the Lower Notch hydroelectric GS.
- During the third quarter, a new control centre was opened at Saunders GS to merge its operations with Chenaux GS. The new control centre will overlook power production at ten hydroelectric stations along the Madawaska, Ottawa and St. Lawrence rivers.
- As part of the process to decommission the Nanticoke and Lambton generating stations, OPG has begun executing demolition plans that will ensure that the stations are closed safely, securely and in an environmentally responsible manner. The demolition of the Nanticoke coal yard equipment and structures is in progress, with a contract issued in July 2017 for the demolition of the Nanticoke powerhouse and associated structures. Project milestones for the Nanticoke site during the remainder of 2017 include completing the removal of coal yard equipment and structures, demolition of the ash silos, and mobilization of the contractor to prepare for removal of the stacks, powerhouse and associated structures. A competitive bidding process for the demolition of the Lambton GS has been completed, with a contract for the removal of the powerhouse and associated buildings expected to be awarded in 2018. An update of the associated asset retirement obligations related to the Nanticoke and Lambton sites is expected to be finalized in the fourth quarter of 2017.

Environmental Performance

There were no significant changes to environmental legislation affecting the Company during the third quarter of 2017. Disclosures related to the Company's environmental policy and environmental risks can be found in OPG's 2016 annual MD&A.

OPG communicates its environmental performance internally to employees and to external stakeholders, including the Ontario Ministry of the Environment and Climate Change, Environment and Climate Change Canada, the CNSC, and local communities. Details of OPG's environmental performance and initiatives to fulfill the Company's Environmental Policy can be found in OPG's 2016 Sustainability Report, available on the Company's website at www.opg.com. **[MONITOR]**

**Project Excellence**

OPG is pursuing a number of generation development and other major projects in support of Ontario's electricity planning initiatives. OPG remains focused on delivering projects safely, on time, on budget and with high quality. The status updates for OPG's major projects as at September 30, 2017 are outlined in the following table, with further details below.

| Project | Capital expenditures | | Approved budget | Expected in-service date | Current status |
|---|---|---|---|---|---|
| *(millions of dollars)* | **Year-to-date** | **Life-to-date** | | | |
| Darlington Refurbishment | 924 | 4,109 | 12,800 [1] | First unit - 2020<br>Last unit - 2026 | The setup of specialized tooling and equipment needed for the removal of reactor components was completed in the third quarter of 2017. All feeder tubes have been removed safely, and the pressure tubes have been severed in preparation for their removal. The Re-tube Waste Processing Building will be available for use in the fourth quarter of 2017. The project is tracking on schedule and on budget. |
| Peter Sutherland Sr. Hydroelectric GS | 38 | 274 | 300 | 2017 | The station was placed in-service on March 31, 2017, ahead of the originally planned schedule, and is expected to close below the approved budget. Project close-out activities are in progress. |
| Ranney Falls Hydroelectric GS | 17 | 20 | 77 | 2019 | Work is progressing on the expanded forebay, forebay wall concrete replacement, powerhouse and spillway areas. The project is tracking on schedule and on budget. |
| Nanticoke Solar Facility | 1 | 2 | 107 **[MONITOR]** | 2019 | Project definition work is continuing, with construction planned to commence in the first quarter of 2018. |
| Deep Geologic Repository for low and intermediate level radioactive waste (L&ILW) | 7 [2] | 202 [2] | | | On August 21, 2017, the federal Minister of Environment and Climate Change requested further information on the project's environmental assessment (EA). OPG is reviewing the new request and will notify the Canadian Environmental Assessment Agency (CEAA) when it has a timeline for submission of that information. |

[1] The total project budget of $12.8 billion is for the refurbishment of all four units at the Darlington GS.
[2] Expenditures are charged against the nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities).

**Commented [A8]:** Does this imply that only 700M further is anticipated to be spent by the time Unit 2 gets completed? (Eg. 4.8B in Capital Expenditure)

Eg. from above:
*"Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service."*

OPG – No, the LTD in the table includes prerequisite projects already declared in-service. The $4.8B was the OEB submitted estimate of a future in-service amount for Unit 2 refurbishment.

Please see updated wording below:

OPG's current application with the OEB for new regulated prices seeks an increase in the nuclear rate base, effective in the first quarter of 2020, to reflect the planned placement in service of the $4.8 billion in capital expenditures upon return to service of Unit 2, which includes expenditures incurred during the definition and planning phase of the project. Based on OPG's proposal in the application, the revenue requirement impact of the differences between the Unit 2 in-service amount included in the regulated prices and the actual amounts placed in service would be subject to true up via the Capacity Refurbishment Variance Account established by the OEB pursuant to *Ontario Regulation 53/05*. OPG's application proposes that the recovery of the HWSF's costs through regulated prices be subject to a separate prudence review by the OEB, to be conducted as part of a future OEB application.

Darlington Refurbishment

The Darlington generating units are approaching their originally designed end-of-life. Refurbishment of the four generating units is expected to extend the operating life of the station by approximately 30 years. OPG commenced the planning of the refurbishment in 2010.

In 2016, the Darlington Refurbishment project transitioned from the planning phase to the execution phase, as OPG commenced the refurbishment of the first unit, Unit 2, in October 2016, as planned. The unit was taken offline on October 15, 2016. De-fuelling of the reactor, the first critical refurbishment activity undertaken once the unit is removed from service, was completed safely in January 2017, with a total of 480 fuel channels de-fuelled. Islanding of Unit 2, the physical separation of the unit under refurbishment from the three operating units, was completed in April 2017, signifying the completion of the first major segment of the project.

The second major segment includes preparatory work to support the removal of feeder tubes and fuel channel assemblies and the removal of reactor components. The preparatory work was completed in the second quarter of 2017. The Re-tube Tooling Platform for hosting the tooling for the removal, inspection, and installation activities and the setup of specialized tooling and equipment needed for the removal and replacement of the reactor components were completed in the third quarter of 2017. The disassembly of reactor components commenced in August 2017, with the removal of all 960 feeder tubes completed safely in September 2017. This was followed by the severing of pressure tubes, with the severing of bellows and the removal of end fittings expected to commence thereafter and through the end of 2017. Other key project activities executed during the second segment include the completion of the primary side steam generator layup, installation of steam generator access ports to support future inspections, continuation of the major turbine generator overhaul and continued execution of the major electrical scope. OPG is also continuing to execute work to support the requirements set out in the CNSC approved IIP for the station.

Once refurbished, Unit 2 is scheduled to be returned to service in the first quarter of 2020, at which time capital expenditures of approximately $4.8 billion are planned to be placed in service. This includes expenditures incurred during the definition and planning phase of the overall project. The project is tracking on schedule and on budget.

With the substantial completion of the Re-tube Waste Processing Building in November 2017, 17 out of 18 pre-requisite projects in support of the execution phase of the project, including construction of facilities, infrastructure upgrades and installation of safety enhancements, have been completed and placed in service. Completion of the Heavy Water Storage and Drum Handling Facility (HWSF) has been delayed due to challenges with construction. OPG suspended the project in the second quarter of 2017 to evaluate the best approach to optimize cost and schedule and complete the project. Construction activities for the HWSF recommenced in the fourth quarter of 2017 following substantial completion of the Re-tube Waste Processing Building. This plan ensures that the necessary resources are available for both projects and, through resource levelling, improves their execution and cost efficiency. The delay in the completion of the HWSF will not impact the overall Darlington Refurbishment project schedule, as the HWSF is not on the project's critical path. This also will not impact the overall project budget of $12.8 billion, as the costs of the HWSF are included in this total figure. The recovery of HWSF costs through regulated prices will be subject to a prudence review by the OEB, which OPG has proposed be conducted as part of a future OEB application.

In addition to the execution of refurbishment activities on Unit 2, OPG is continuing planning activities for the refurbishment of the second unit, Unit 3, and is entering into associated commitments to procure major components that require long lead times. As of September 30, 2017, $70 million has been invested in planning activities related to the refurbishment of the second unit, Unit 3. These planning activities are being undertaken in accordance with the refurbishment project schedule.

The Financial Accountability Office of Ontario has issued a report titled "*An Assessment of the Financial Risks of the Nuclear Refurbishment Plan*". The report assesses both OPG and Bruce Power's refurbishment activities and the method in which those refurbishments and subsequent nuclear generation is provided to the marketplace. The report

concludes that the base case of refurbishing the six units at the Bruce nuclear GS and the four units at the Darlington nuclear GS provide the most cost effective, low emission generation source available to meet Ontario's baseload electricity requirements. This report re-affirms the positive economic and societal benefits associated with a strong nuclear program in the Province. **[MONITOR]**

Commented [A9]: Not yet released.

OPG – We put MONITOR to ensure status next Thursday before we release.

Ranney Falls Hydroelectric GS

During the third quarter of 2017, OPG continued construction work for a 10 MW single-unit powerhouse on the existing Ranney Falls GS site, as part of the Regulated – Hydroelectric segment. The new unit will replace an existing unit that reached its end of life in 2014. The existing forebay structure demolition has been completed and the upstream cofferdam has been constructed ahead of schedule. Construction continues on the expanded forebay, powerhouse and spillway. Excavation work is substantially complete and forebay wall concrete replacement is in progress. The project's expected in-service date is in the fourth quarter of 2019, with a budget of $77 million. The project is tracking on schedule and on budget.

Nanticoke Solar Facility

The construction of a 44 MW solar facility at OPG's Nanticoke GS site and adjacent lands under a Large Renewable Procurement contract with the IESO, through Nanticoke Solar LP, a partnership between OPG and a subsidiary of the Six Nations of Grand River Development Corporation, is planned to commence in the first quarter of 2018. During the third quarter of 2017, the partnership continued work to obtain approvals and permits required to enable the commencement of construction, and progressed procurement activities for equipment and for engineering and construction services. The facility is expected to be completed in the first quarter of 2019.

Deep Geologic Repository for Low and Intermediate Level Waste

OPG has proposed a deep geologic repository as the preferred solution for the safe long-term management of the L&ILW produced from the continued operation of OPG-owned nuclear generating stations. Agreement has been reached with local municipalities for OPG to develop the L&ILW Deep Geologic Repository (DGR) on lands adjacent to the Western Waste Management Facility (WWMF) in Kincardine, Ontario. The environmental effects of the proposed L&ILW DGR were examined by the CNSC and CEAA-appointed Joint Review Panel (JRP) to meet the requirements of the Canadian Environmental Assessment Act. The JRP submitted its report on the EA to the federal Minister of Environment in May 2015, concluding that, given mitigation, there is unlikely to be significant environmental impact from the project and recommending that the Minister approve the EA. In December 2016, at the request of the federal Minister of Environment and Climate Change, OPG submitted additional information on certain aspects of the EA, including information related to alternate locations for the project. Following its review of OPG's submission and a period of public comment, the CEAA requested further information that OPG subsequently provided in May 2017. In June 2017, the CEAA notified OPG that it had sufficient and adequate information to proceed with the next step of the environmental assessment process and advised that a draft report and updated terms and conditions will be prepared for public review.

On August 21, 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of potential cumulative effects of the project on the Saugeen Ojibway Nations' (SON) physical and cultural heritage, including a description of the potential effects of the project on the Nation's spiritual and cultural connection to the land. OPG is assessing the request and will notify the CEAA when it has determined the timeline for developing a response. The CEAA's draft report for public review will not be issued until this update is provided. The L&ILW DGR at the WWMF site remains OPG's preferred solution for the safe long-term management of the L&ILW.

OPG continues its engagement with the SON toward securing community support for the L&ILW DGR. The in-service date of the L&ILW DGR is expected to be approximately six to seven years from the start of construction.

## Financial Strength

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of strong financial performance that delivers an appropriate level of return on the Shareholder's investment and positions the Company for future growth.

Increase Revenue, Reduce Costs and Achieve Appropriate Return

In May 2016, OPG filed a 5-year application with the OEB for new regulated prices for production from its regulated hydroelectric and nuclear facilities, with a proposed effective date of January 1, 2017. Consistent with the requirements of *Ontario Regulation 53/05*, the application incorporates a rate smoothing proposal that would defer, for future collection, a portion of the approved annual nuclear revenue requirement for the period from January 1, 2017 to the end of the Darlington Refurbishment project, with a view to making changes in OPG's regulated prices more stable year-over-year. The application seeks to ensure that nuclear regulated prices under the rate smoothing approach allow for sufficient cash flow to meet the Company's liquidity needs, support cost effective funding for the Darlington Refurbishment project and other expenditures, and maintain the Company's investment grade credit rating, while taking into account both near-term and future impacts on customers. OPG expects to recognize amounts deferred under rate smoothing as income in the periods to which the underlying approved revenue requirements relate.

The application will further challenge and incentivize OPG to find additional cost reductions and efficiencies within its operations, as a result of greater de-coupling of nuclear and hydroelectric regulated prices from costs and a longer rate-setting period under the OEB's incentive ratemaking framework, which forms the basis for the ratemaking methodologies reflected in the application.

The application seeks an increase in the nuclear rate base, effective in early 2020, to reflect the planned placement in service of approximately $4.8 billion of capital expenditures upon the scheduled return to service of Unit 2 at the Darlington GS as part of the Darlington Refurbishment project and, effective in 2017, an increase in the deemed capital structure applied to the total regulated rate base to 49 percent equity and 51 percent debt, from 45 percent equity and 55 percent debt reflected in the existing regulated prices. The application also requests new rate riders, effective January 1, 2017, to recover or repay the December 31, 2015 balances in all of the Company's OEB-authorized variance and deferral accounts, with the exception of the Pension & OPEB Cash Versus Accrual Differential Deferral Account and the portion of these balances previously approved for recovery or repayment through rate riders that were in effect during 2016.

The OEB's decision on the application, including the effective date of approved new regulated prices, is expected later in 2017. **[MONITOR]**

For generation assets that do not form part of the assets regulated by the OEB, OPG's strategy has been to secure appropriate long-term revenue arrangements. In line with this strategy, virtually all of OPG's non-regulated operating facilities and assets under construction are subject to long-term Energy Supply Agreements (ESAs) or other long-term contracts with the IESO.

Ensure Availability of Cost Effective Funding

In April 2017, DBRS Limited (DBRS) re-affirmed the long-term credit rating on OPG's debt at 'A (low)' and OPG's commercial paper rating at 'R-1 (low)'. All ratings from DBRS have a stable outlook. In July 2017, S&P Global Ratings (S&P) re-affirmed OPG's long-term credit rating at 'BBB+' with a stable outlook. S&P's commercial paper rating for OPG is 'A-1 (low)'.

## Social Licence

As the largest electricity generator in Ontario with diverse operations across the province, OPG holds itself accountable to the public and its employees, and continues to focus on maintaining public trust. OPG is committed to maintaining high standards of public safety and corporate citizenship, including environmental stewardship, transparency, community engagement, and Indigenous relations.

OPG is focused on building long-term, mutually beneficial working relationships with Indigenous communities, businesses and organizations across Ontario, and continues to support procurement, employment and educational opportunities with its Indigenous community partners. The Company seeks to establish these relationships based on a foundation of respect for the languages, customs, and political, social and cultural organizations of the Indigenous communities.

In June 2017, OPG launched an Indigenous Business Engagement (IBE) Initiative. The purpose of this initiative is to increase access to procurement opportunities for Indigenous businesses interested in supplying materials and services to OPG. The IBE Initiative is based on a strategy that will identify opportunities in contracts, scopes of work and business plans for potential Indigenous business engagement; include criteria related to suppliers' ability to engage or partner with Indigenous people or businesses in assessing procurement proposals; and invest in relationships with Indigenous communities by increasing outreach efforts to enhance understanding of how to do business with OPG. OPG has continued to engage with various Indigenous business and communities as well as its suppliers to promote the IBE Initiative. In September 2017, OPG presented the IBE to the Mohawk Council of Akwesanse (Akwesanse). As a result, Akwesanse plans to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG. In September 2017, OPG also hosted a similar presentation to the Williams Treaties First Nations, located proximate to the Pickering and Darlington Nuclear Generating Stations, at the quarterly meeting for these communities.

OPG is developing recruitment plans targeting Indigenous people. In October 2017, OPG participated in five Indigenous-specific career fairs to attract such talent. **[MONITOR]**

OPG has a transportation electrification strategy that will help position OPG as a leader in transportation electrification in Ontario. This strategy is intended to leverage OPG's clean electricity to support action on climate change, create growth opportunities for OPG, and enhance OPG's brand and social licence.

## Outlook

The financial performance of OPG's regulated operations is driven, in large part, by the outcome of applications for regulated prices to the OEB. The existing base regulated prices were established by the OEB effective November 1, 2014 based on a forecast of costs and production for the regulated facilities for the 2014 to 2015 period. The future outcome of OPG's current application for new regulated prices, currently pending the OEB's decision, is expected to provide substantial price certainty for the regulated business for the 2017 to 2021 period.

In its application, OPG has requested January 1, 2017 as the effective date for the new regulated prices. In December 2016, the OEB issued an order declaring the existing base regulated prices interim, which preserves the OEB's ability to make the new regulated prices effective as early as January 1, 2017. Considering the timing of OPG's application and OPG's procedural adherence throughout the proceeding, the Company believes that the OEB could make the new regulated prices effective January 1, 2017. This would allow OPG to recover the difference between the approved new regulated prices and the existing regulated prices for the period between January 1, 2017 and the implementation date of the new prices based on the OEB's order. The OEB's decision on the application, including the effective date of the new regulated prices, is expected in the fourth quarter of 2017. **[MONITOR]** The continuation of existing regulated prices until the issuance of the OEB's decision is expected to continue to contribute to lower income, particularly from the Regulated – Nuclear Generation segment, and, excluding the gain on sale of the Company's head office premises and associated parking facility recorded in the second quarter of 2017, lower

**Commented [A10]:** Sp. "Akwesasne" ?

OPG – fixed spelling to as follows:

In September 2017, OPG presented the IBE to the Mohawk Council of Akwesasne (Akwesasne). As a result, the Akwesasne plan to create a database of businesses in the community that will participate in contracting and supply opportunities with OPG.

**Commented [A11]:** Does this deal with OPG owned fleet and other vehicles, or in line with the infrastructure for EV vehicles.

Can further details be provided in particular on the point of 'creating growth opportunities for OPG'.

OPG – revised wording for this paragraph as follows:

OPG has a strategy to help position the Company as a leader in transportation electrification in the province. The strategy aims to leverage the Company's clean, reliable and cost-effective electricity to power transportation, capitalize on future commercial growth opportunities, and enhance the Company's social licence. OPG is pursuing initiatives to increase the use of electric vehicles within its operations, and is assessing vehicle grid integration and hydrogen applications for the transportation sector.

ROE Excluding AOCI during 2017, compared to 2016. In large part, this is due to the year-over-year reduction in nuclear electricity generation resulting from the Unit 2 refurbishment outage at the Darlington GS, given that the existing nuclear regulated prices were determined in 2014 based on a higher production forecast that reflected the operation of all four units at the station. As such, the OEB's decision on the effective date of the new regulated prices, as well as the timing of the decision issuance, could have a significant impact on OPG's financial results during 2017.

Nuclear base regulated prices resulting from OPG's current application will be subject to a rate smoothing mechanism that defers collection of a portion of OEB-approved revenues to future periods. As expected, combined with the expiry of rate riders in effect to the end of 2016, a year-over-year reduction in nuclear generation due to the Unit 2 refurbishment outage at the Darlington GS and the continuation of existing regulated prices until such time as new prices are implemented by the OEB, this will result in lower cash flow from operating activities in 2017, compared to 2016. OPG expects to continue to have the necessary financial capacity and sufficient access to cost effective financing sources to continue to fund its capital requirements and other disbursements.

Lower nuclear generation due to the Darlington Refurbishment outages will continue, as planned, to negatively impact the Enterprise TGC metric for the duration of the refurbishment project. Variability in sustaining capital investment expenditures, including major sustaining projects for the hydroelectric operations, also will impact the Enterprise TGC in future periods.

Several OEB-authorized regulatory variance and deferral accounts currently in place contribute to reducing the relative variability of the Company's income and ROE Excluding AOCI. Among others, the regulatory accounts include those related to the revenue impact of variability in water flows and forgone production due to SBG conditions at the regulated hydroelectric stations. As there are no variance or deferral accounts in place related to the impact of generation performance of the nuclear stations on revenue from base regulated prices, the Regulated – Hydroelectric segment generally is expected to produce overall more predictable earnings. OPG continues to operate and maintain its nuclear facilities with a view to optimize their performance and availability, while focusing on improving the overall reliability and predictability of the fleet.

Electricity generated from most of OPG's non-regulated assets is subject to ESAs with the IESO. Based on these agreements, OPG expects the Contracted Generation Portfolio segment to continue to contribute a generally stable level of earnings and cash flow from operations going forward.

OPG's total forecast capital expenditures for the 2017 year are approximately $2.0 billion. This includes amounts for the Darlington Refurbishment project, hydroelectric and other development projects including the completion of the Peter Sutherland Sr. GS and the expansion of the Ranney Falls GS, and sustaining capital investments across the generating fleet. OPG's major projects are discussed in the section, *Project Excellence*.

In addition to the operating and financial performance of the electricity generation business, OPG's results are affected by the earnings on the Nuclear Segregated Funds, which are reported in the Regulated – Nuclear Waste Management segment. While the Nuclear Segregated Funds are managed to achieve, in the long term, the target rate of return based on the discount rate specified in the ONFA, the rates of return earned in a given period can be subject to various external factors including financial market conditions and, for the portion of the Used Fuel Segregated Fund guaranteed by the Province under the ONFA, changes in the Ontario consumer price index (CPI). In the near term, these factors can be volatile and cause fluctuations in the Company's income. This volatility is partially mitigated by the impact of the OEB-authorized Bruce Lease Net Revenues Variance Account and, as discussed below, the funded status of the two segregated funds.

As OPG does not have the right to withdraw surplus amounts from the Nuclear Segregated Funds, OPG limits the amount of Nuclear Segregated Funds assets reported on the balance sheet to the present value of such life cycle funding liability. This reduces the volatility of earnings on the Nuclear Segregated Funds reflected in net income when the funds are in a fully funded or overfunded position. As at September 30, 2017, the Decommissioning

Segregated Fund was overfunded by approximately 23 percent, and the Used Fuel Segregated Fund was marginally overfunded, by less than one percent, based on the 2017 ONFA Reference Plan. Variability in asset performance due to volatility inherent in financial markets and changes in Ontario CPI, or changes in funding liability estimates, may result in either or both funds becoming underfunded in the future.

## DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

### Regulated – Nuclear Generation Segment

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **739** | 885 | **2,000** | 2,631 |
| Fuel expense | **81** | 79 | **217** | 239 |
| Gross margin | **658** | 806 | **1,783** | 2,392 |
| Operations, maintenance and administration | **511** | 521 | **1,693** | 1,665 |
| Depreciation and amortization | **116** | 230 | **333** | 691 |
| Property taxes | **7** | 6 | **20** | 19 |
| Income (loss) before other losses, interest, and income taxes | **24** | 49 | **(263)** | 17 |
| Other losses | **4** | 2 | **4** | - |
| Income (loss) before interest and income taxes | **20** | 47 | **(267)** | 17 |

For the three and nine month periods ended September 30, 2017, the segment earnings decreased by $27 million and $284 million, respectively, compared to the same periods in 2016. The decrease in earnings was expected and primarily due to reduced revenue from the nuclear base regulated price of approximately $24 million and $230 million, respectively. The decrease was partially offset by an associated year-over-year decrease in fuel expense. The decrease in revenue during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, reflected lower electricity generation of 0.4 TWh and 4.0 TWh, respectively, primarily due to the ongoing Unit 2 refurbishment outage at the Darlington GS that began in October 2016, without a corresponding increase in the base regulated price. The existing nuclear base regulated price set by the OEB in 2014 continues to be in effect pending the OEB's decision on OPG's application for new regulated prices, proposed to be effective on January 1, 2017. The existing price does not reflect the lower generation as a result of the Darlington Refurbishment project, as it was set to allow the Company to recover its approved nuclear costs over a higher nuclear production volume, based on the 2014 and 2015 outage profile that did not include a refurbishment outage. The reduction in nuclear electricity generation for the three months ended September 30, 2017 was largely offset by the higher electricity generation from the Pickering GS.

OM&A expenses decreased by $10 million during the third quarter of 2017, compared to the same period in 2016, as a result of a higher materials and supplies obsolescence charge recognized in 2016. OM&A expenses increased by $28 million during the nine months ended September 30, 2017, compared to the same period in 2016, due to planned maintenance activities in 2017.

Depreciation and amortization expense, excluding amortization expense related to regulatory account balances, increased by $16 million and $30 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016, primarily due to new assets in service.

The expiry of an OEB-authorized nuclear rate rider on December 31, 2016 contributed to the decrease in segment revenue for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016. As rate riders allow for recovery of approved balances in OEB-authorized regulatory accounts, this decrease in revenue was largely offset by a decrease in amortization expense related to these balances. There was no rate rider

in effect during the nine months ended September 30, 2017, pending the outcome of OPG's current application to the OEB for new regulated prices.

The Unit Capability Factors for the Darlington and Pickering generating stations were as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Unit Capability Factor *(%)* [1] | | | | |
| Darlington GS | **96.2** | 89.6 | **82.1** | 87.6 |
| Pickering GS | **88.7** | 77.3 | **83.8** | 73.8 |

[1] The nuclear Unit Capability Factor excludes unit(s) during the period in which they are undergoing refurbishment. Accordingly, Unit 2 of the Darlington GS was excluded from the measure effective October 15, 2016, when the unit was taken offline for refurbishment.

The Unit Capability Factor at the Darlington GS increased in the third quarter of 2017, compared to the same quarter in 2016, primarily due to the lower number of planned outage days during the third quarter of 2017. The lower Unit Capability Factor at the Darlington GS for the nine months ended September 30, 2017, compared to the same period in 2016, reflected the higher number of planned outage days, largely driven by constraints related to the transition of the station toward refurbishment.

The increase in Unit Capability Factor at the Pickering GS for the three and nine month periods ended September 30, 2017 was primarily due to outage optimization, favourable unit conditions and execution of planned outage work resulting in a lower number of unplanned and planned outage days at the station compared to 2016.

**Regulated – Nuclear Waste Management Segment**

| *(millions of dollars) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Revenue | **33** | 36 | **90** | 102 |
| Operations, maintenance and administration | **35** | 38 | **96** | 108 |
| Accretion on nuclear fixed asset removal and nuclear waste management liabilities | **230** | 228 | **696** | 684 |
| Earnings on nuclear fixed asset removal and nuclear waste management funds | **(196)** | (248) | **(579)** | (620) |
| (Loss) Income before interest and income taxes | **(36)** | 18 | **(123)** | (70) |

The segment loss before interest and income taxes was $36 million and $123 million during the three and nine months ended September 30, 2017, respectively, a decrease in earnings of $54 million and $53 million compared to the same periods in 2016. The decline in earnings was primarily due to lower earnings from the Nuclear Segregated Funds, net of the impact of the impact of the Bruce Lease Net Revenues Variance Account, reflecting higher earnings from market returns on fund assets and the CPI-adjusted rate of return guaranteed by the Province for the portion of the Used Fuel Segregated Fund related to the initial 2.23 million used fuel bundles (committed return) in the third quarter of 2016.

As both the Decommissioning Segregated Fund and the Used Fuel Fund were in an overfunded position during the three and nine months period ended September 30, 2017, compared to the underlying funding liabilities per the approved ONFA Reference Plan, the earnings on the funds during these periods reflected the growth rate in the present value of the funding liabilities and were not impacted by market returns and committed return. The higher earnings on both funds during the three and nine months periods ended September 30, 2016 reflected market returns and committed return, as the Decommissioning Segregated Fund became over 120 percent funded during the third quarter of 2016 while the Used Fuel Fund was underfunded, compared to the corresponding funding liabilities.

Higher market returns and committed return in the third quarter of 2016 in relation to the funding liabilities' growth rate reflected in fund earnings during 2017 resulted in a year-over-year decrease in the amount of earnings on the Nuclear Segregated Funds.

As of December 31, 2016, OPG recorded a decrease of approximately $1,570 million to the Nuclear Liabilities and associated asset retirement costs capitalized as part of the carrying value of the nuclear generating stations. The resulting year-over-year decreases in accretion on fixed asset removal and nuclear waste management liabilities recorded in the Regulated – Nuclear Waste Management segment and depreciation and fuel expenses recorded in the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, were offset by the impact of the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB.

Under the current OEB-approved cost recovery methodology, these changes in expenses also are not expected to materially affect OPG's income during the rest of 2017, as they are expected to continue to be largely offset by the impact of the regulatory accounts until such time as the OEB implements corresponding changes to OPG's nuclear regulated prices, and subsequently by the impact of such new regulated prices. Further details on the change in the estimate of the Nuclear Liabilities as of December 31, 2016 are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Asset Retirement Obligation*. **[MONITOR]**

**Regulated – Hydroelectric Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue [1] | **327** | 350 | **1,069** | 1,148 |
| Fuel expense | **88** | 88 | **258** | 259 |
| Gross margin | **239** | 262 | **811** | 889 |
| Operations, maintenance and administration | **81** | 87 | **232** | 238 |
| Depreciation and amortization | **34** | 56 | **103** | 169 |
| Property tax | **1** | 1 | **1** | 1 |
| Income before other losses (gains), interest and income taxes | **123** | 118 | **475** | 481 |
| Other losses (gains) | **1** | 1 | **1** | (19) |
| Income before interest and income taxes | **122** | 117 | **474** | 500 |

[1] During the three and nine month periods ended September 30, 2017, the Regulated – Hydroelectric segment revenue included incentive payments of $4 million and $9 million, respectively, related to the OEB-approved hydroelectric incentive mechanism (three and nine month periods ended September 30, 2016 – incentive payments of $6 million and $8 million, respectively). The mechanism provides a pricing incentive to OPG to shift hydroelectric production from lower market price periods to higher market price periods, reducing the overall costs to customers. The incentive payments are reduced to remove incentive revenues arising in connection with SBG conditions.

The increase in segment income before interest and income taxes of $5 million during the third quarter of 2017, compared to the same quarter in 2016, was primarily the result of a decrease in OM&A expenses, mainly due to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in segment income before interest and income taxes of $26 million during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a gain of $22 million recognized during the first quarter of 2016 to reflect the OEB's January 2016 decision to reverse a portion of an earlier capital cost disallowance related to the Niagara Tunnel project expenditures, in response to a motion by OPG. The income impact of OEB-approved variance accounts also contributed to the year-over-year decrease in income for the period. These factors were partially offset by the decrease in OM&A expenses related to the timing of repairs and maintenance work in 2017 and a deferral of outages during the high water period.

The decrease in revenue from the segment for the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was largely due to the expiry of an OEB-authorized rate rider on

December 31, 2016. As the rider allowed for the recovery of approved balances in OEB-authorized regulatory accounts, the resulting reduction in revenue was largely offset by lower amortization expense related to these balances. There was no rate rider in effect during the first nine months of 2017 pending the outcome of OPG's current application to the OEB for new regulated prices.

The Hydroelectric Availability for the stations included in the Regulated – Hydroelectric segment was as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric Availability *(%)* | **87.6** | 84.1 | **89.0** | 89.8 |

The Hydroelectric Availability in the third quarter of 2017 was higher compared to the same period in 2016, primarily due to a higher number of planned outages in 2016 as a result of the refurbishment of the Sir Adam Beck Pump GS reservoir between April 2016 and February 2017. The marginal decrease in Hydroelectric Availability during the nine months ended September 30, 2017, compared to the same period in 2016, was primarily due to a higher number of unplanned outage days at the Northwestern Ontario and Niagara region hydroelectric stations, partially offset by higher availability from the Sir Adam Beck Pump GS.

**Contracted Generation Portfolio Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **141** | 149 | **431** | 431 |
| Fuel expense | **15** | 19 | **42** | 42 |
| Gross margin | **126** | 130 | **389** | 389 |
| Operations, maintenance and administration | **39** | 44 | **118** | 129 |
| Depreciation and amortization | **20** | 19 | **59** | 56 |
| Accretion on fixed asset removal liabilities | **3** | 2 | **7** | 6 |
| Property taxes | **-** | 1 | **5** | 6 |
| Income from investments subject to significant influence | **(11)** | (11) | **(29)** | (28) |
| Income before other loss, interest and income taxes | **75** | 75 | **229** | 220 |
| Other loss | **-** | 1 | **-** | 1 |
| Income before interest and income taxes | **75** | 74 | **229** | 219 |

Income before interest and income taxes from the segment increased by $1 million and $10 million during the three and nine month periods ended September 30, 2017, respectively, compared to the same periods in 2016. The increase in earnings for the three months ended September 30, 2017 mainly resulted from revenues from the Peter Sutherland Sr. GS that was placed in-service at the end of the first quarter of 2017 and lower OM&A expenses, partially offset by lower revenue from the Atikokan GS. The decrease in revenue from the Atikokan GS was primarily due to higher revenues in 2016, when the station was called upon to provide the needed support to the electricity system in Northwestern Ontario as a result of an outage at a local transformer station. For the nine months ended September 30, 2017, the increase in earnings was primarily due to lower OM&A expenses. The lower OM&A expenses for the three and nine month periods ended September 30, 2017 were mainly due to the prospective adoption of the full yield curve approach to the estimation of the service and interest cost components of pension and OPEB costs starting in 2017.

The Hydroelectric Availability and the Thermal Equivalent Forced Outage Rate (EFOR) for the Contracted Generation Portfolio segment were as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric Availability *(%)* | **66.1** | 68.2 | **76.9** | 79.6 |
| Thermal EFOR *(%)* | **2.6** | 2.1 | **6.0** | 1.3 |

Lower Hydroelectric Availability during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to an increase in the number of planned outage days at the Lower Mattagami River hydroelectric generating stations.

The higher Thermal EFOR during the three and nine month periods ended September 30, 2017, compared to the same periods in 2016, was primarily due to a higher number of unplanned outage days at a Lennox GS unit as a result of a transmission outage and a generator cooling water system outage in 2017.

**Services, Trading, and Other Non-Generation Segment**

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Revenue | **9** | 15 | **36** | 52 |
| Fuel expense | **1** | 1 | **1** | 1 |
| Gross margin | **8** | 14 | **35** | 51 |
| Operations, maintenance and administration | **1** | 11 | **2** | 20 |
| Depreciation and amortization | **8** | 8 | **22** | 25 |
| Accretion on fixed asset removal liabilities | **2** | 2 | **6** | 6 |
| Property taxes | **-** | 4 | **4** | 9 |
| (Loss) income before other gains, interest, and income taxes | **(3)** | (11) | **1** | (9) |
| Other gains | **(2)** | (3) | **(385)** | (5) |
| Income (loss) before interest and income taxes | **(1)** | (8) | **386** | (4) |

Segment earnings improved by $7 million during the third quarter of 2017, compared to the same quarter in 2016. The improvement in earnings was primarily due to lower OM&A expenses reflecting project expenditures incurred in the third quarter of 2016, and OPG's decision, in the fourth quarter of 2016, to proceed with the decommissioning of Lambton GS.

Segment income before interest and income taxes increased by $390 million for the nine months ended September 30, 2017, compared to the same period in 2016. The increase in earnings mainly reflected the gain on the sale of OPG's head office premises and associated parking facility recorded during the second quarter of 2017.

## LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital are funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEFC), long-term corporate debt, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies, to undertake major projects, to fund long-term obligations such as contributions to the pension fund and the Nuclear Segregated Funds, to make payments under the OPEB plans, to fund expenditures on Nuclear Liabilities not reimbursable from the Nuclear Segregated Funds, to service and repay long-term debt, to provide general working capital, and to fund OPG's investment in the Fair Hydro Plan.

Changes in cash and cash equivalents for the three and nine month periods ended September 30 are as follows:

| | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| *(millions of dollars) (unaudited)* | **2017** | **2016** | **2017** | **2016** |
| Cash and cash equivalents, beginning of period | **242** | 295 | **186** | 464 |
| Cash flow provided by operating activities | **485** | 530 | **698** | 1,211 |
| Cash flow used in investing activities | **(463)** | (390) | **(720)** | (1,253) |
| Cash flow provided by (used in) financing activities | **16** | (9) | **116** | 4 |
| Net increase (decrease) | **38** | 131 | **94** | (38) |
| Cash and cash equivalents, end of period | **280** | 426 | **280** | 426 |

For a discussion of cash flow provided by operating activities and the FFO Adjusted Interest Coverage ratio, refer to the details in the section, *Highlights* under the heading, *Overview of Results*.

### Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to maintain and improve operating performance including asset reliability, safety and environmental performance, to increase the generating capacity of existing stations, and to invest in the development of new generating stations, emerging technologies and other business growth opportunities.

Cash flow used in investing activities during the third quarter of 2017 was $463 million, compared to $390 million for the same period in 2016. The increase in cash flow used for investing activities mainly resulted from higher expenditures on the Darlington Refurbishment project in the third quarter of 2017.

Cash flow used in investing activities decreased by $533 million for the nine months ended September 30, 2017, compared to the same period in 2016. The decrease in net cash flow used in investing activities was primarily due to the receipt of proceeds from the sale of OPG's head office premises and associated parking facility in the second quarter of 2017 pursuant to a Shareholder Declaration and Shareholder Resolution, and the acquisition of nine million common shares of Hydro One Limited (Hydro One) in the second quarter of 2016, partially offset by higher expenditures on the Darlington Refurbishment project in 2017. OPG acquired the Hydro One shares for investment purposes, to mitigate the risk of future price volatility related to the Company's future share delivery obligations under the collective agreements with the Power Workers' Union and The Society of Energy Professionals.

Pursuant to the Shareholder Declaration and Shareholder Resolution, and as prescribed in the *Trillium Trust Act, 2014*, OPG is required to transfer the proceeds from the sale of head office premises and associated parking facility, net of prescribed deductions under the Act, into the Province's Consolidated Revenue Fund. OPG expects that the amount of designated proceeds to be transferred into the Consolidated Revenue Fund will be largely consistent with the after-tax gain on sale. The transfer is expected to take place later in 2017.

## Financing Activities

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In the second quarter of 2017, OPG renewed and extended the expiry date of both tranches from May 2021 to May 2022. There were no amounts outstanding under the bank credit facility as at September 30, 2017.

There was $160 million of commercial paper outstanding under OPG's commercial paper program as at September 30, 2017.

As at September 30, 2017, OPG also maintained $25 million of short-term, uncommitted overdraft facilities, and a further $463 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other general corporate purposes. As at September 30, 2017, a total of $388 million of Letters of Credit had been issued under these facilities. This included $349 million for the supplementary pension plans, $38 million for general corporate purposes, and $1 million related to the operation of the PEC.

The Company has an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust, expiring on November 30, 2018. The maximum amount of co-ownership interest that can be sold under this agreement is $150 million. As at September 30, 2017, no borrowings were issued under this agreement and there were Letters of Credit outstanding under this agreement of $150 million, which were issued in support of OPG's supplementary pension plans.

As at September 30, 2017, Lower Mattagami Energy Limited Partnership (LME) maintained a $400 million bank credit facility to support the funding requirements for the Lower Mattagami River project including support for LME's commercial paper program and the issuance of the Letters of Credit. The facility consists of a $300 million tranche which, in the third quarter of 2017, was extended to mature in August 2022 and a $100 million tranche which, in the third quarter of 2017, was reduced from $200 million and extended to mature in August 2018. As at September 30, 2017, there was no external commercial paper outstanding under LME's commercial paper program. A letter of credit of $55 million was issued in July 2017 and remains outstanding as at September 30, 2017 under the $300 million tranche of the credit facility.

In June 2016, OPG entered into a $700 million general corporate credit facility agreement with the OEFC, which expires on December 31, 2017. In the third quarter of 2017, the agreement was amended to increase the credit facility to $2,350 million and to extend its expiry date to December 31, 2018.

In February 2017, OPG issued senior notes payable to the OEFC totalling $200 million and maturing in February 2047. The effective interest rate and coupon interest rate of these notes was 4.12 percent. In June 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in June 2047. The effective interest rate and coupon interest rate of these notes was 3.65 percent. In August 2017, OPG issued senior notes payable to the OEFC totalling $100 million and maturing in August 2047. The effective interest rate and coupon interest rate of these notes was 3.86 percent. In September 2017, OPG issued senior notes payable to the OEFC totalling $400 million and maturing in September 2047. The effective interest rate and coupon interest rate of these notes was 4.07 percent. As at September 30, 2017, there were outstanding long-term borrowings of $800 million under this credit facility.

In October 2017, OPG issued $500 million of senior notes payable under a Medium Term Note Program. The notes bear a coupon interest rate of 3.32 percent and an effective rate of 3.43 percent, payable semi-annually until maturity on October 4, 2027. The offering was made under OPG's $2 billion short form base shelf prospectus dated September 12, 2017. The net proceeds will be used for general corporate purposes, including the financing of OPG's subordinated debt investment in the Fair Hydro Plan.

As at September 30, 2017, OPG's long-term debt outstanding was $5,482 million, including $628 million due within one year.

OPG continues to evaluate arrangements that would appropriately support the Company's financing needs and capital expenditure programs.

### Contractual and Commercial Commitments

Pension Plan Actuarial Valuation

A new actuarial valuation of the OPG registered pension plan was filed with the Financial Services Commission of Ontario in September 2017 with an effective date of January 1, 2017. The annual funding requirements in accordance with the new actuarial valuation are $212 million for 2017, $215 million for 2018, and $219 million for 2019. The next actuarial valuation must have an effective date no later than January 1, 2020.

## BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

| *(millions of dollars) (unaudited)* | As At September 30 2017 | As At December 31 2016 |
|---|---|---|
| **Property, plant and equipment - net** | **20,801** | 19,998 |
| The increase was primarily due to capital expenditures on the Darlington Refurbishment project, partially offset by depreciation expense. | | |
| **Nuclear fixed asset removal and nuclear waste management funds** *(current and non-current portions)* | **16,534** | 15,984 |
| The increase was primarily due to earnings on the Nuclear Segregated Funds, partially offset by reimbursements of eligible expenditures on nuclear fixed asset removal and nuclear waste management activities. | | |
| **Short-term debt** | **160** | 2 |
| The increase was due to commercial paper issued under OPG's commercial paper program during the third quarter of 2017. | | |
| **Fixed asset removal and nuclear waste management liabilities** | **20,075** | 19,484 |
| The increase was primarily a result of accretion expense representing the increase in the liabilities due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities. | | |

### Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under US GAAP, are either not recorded in the Company's interim consolidated financial statements or are recorded in the Company's interim consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities for OPG include guarantees and long-term contracts.

## CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies are outlined in Note 3 to the audited consolidated financial statements as at and for the year ended December 31, 2016. A discussion of recent accounting pronouncements and change in accounting estimate are included in Note 2 to OPG's unaudited interim consolidated financial statements as at and for the three and nine month periods ended September 30, 2017 under the heading, *Significant Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2016 annual MD&A.

## RISK MANAGEMENT

The following provides an update to the discussion of the Company's risks and risk management activities included in OPG's 2016 annual MD&A. As such, the disclosure in this section should be read in conjunction with the *Risk Management* section included in the annual MD&A.

### Risks to Achieving Project Excellence

Deep Geologic Repository for Low and Intermediate Level Waste

In August 2017, the federal Minister of Environment and Climate Change requested OPG to update its analysis of the potential cumulative effects of the DGR project on the physical and cultural heritage of the SON, taking into account the results of the SON Community Process. OPG continues to work with the SON, however the timing and outcome of the SON Community Process and the EA decision by the Minister are uncertain.

### Risks to Maintaining Financial Strength

Commodity Markets

*Changes in the market price of fuels used to produce electricity can adversely impact OPG's earnings and cash flow from operations.*

To manage the risk of unpredictable increases in the price of fuels, the Company has fuel hedging programs, which include fixed price and indexed contracts.

The percentages hedged of OPG's fuel requirements are shown in the following table. These amounts are based on yearly forecasts of generation and supply mix, and as such, are subject to change as these forecasts are updated.

| | 2017 [1] | 2018 | 2019 |
|---|---|---|---|
| Estimated fuel requirements hedged [2] | 73% | 73% | 69% |

[1] Based on actual fuel requirements hedged for the nine months ended September 30, 2017 and forecast for the remainder of the year.

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of OPG-operated facility (nuclear, hydroelectric and thermal) for which the Company has entered into contractual arrangements or obligations in order to secure the price of fuel, or which is subject to regulation. In the case of hydroelectric generation, this represents the gross revenue charge and water rental charges. Excess fuel inventories (nuclear and thermal) in a given year are attributed to the next year for the purpose of measuring hedge ratios.

Foreign Exchange

*OPG's earnings and cash flow can be affected by movements in the United States dollar (USD) relative to the Canadian dollar.*

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels and certain supplies and services purchased for generating stations and major development projects are denominated in, or tied to, USD. To manage this risk, OPG periodically employs various financial instruments such as forwards and other

derivative contracts, in accordance with approved risk management policies. As at September 30, 2017, OPG had no foreign exchange contracts outstanding.

Trading

*OPG's financial performance can be affected by its trading activities.*

OPG's electricity trading operations are closely monitored, with total exposures measured and reported to senior management on a daily basis. The main metric used to measure the financial risk of trading activity is Value at Risk (VaR). VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For the third quarter of 2017, the VaR utilization ranged between $0.2 million and $0.3 million.

Credit

*Deterioration in energy markets counterparty credit and non-performance by suppliers and contractors can adversely impact OPG's earnings and cash flow from operations.*

OPG manages its exposure to suppliers or counterparties by evaluating their financial condition and negotiating appropriate collateral or other forms of security. OPG's credit exposure relating to energy markets transactions as at September 30, 2017 was $356 million, including $346 million with the IESO. Management considers the Company's risk exposure relating to electricity sales through the IESO-administered spot market to be low as the IESO oversees the credit worthiness of all market participants. In accordance with the IESO's prudential support requirements, market participants are required to provide collateral to cover funds that they might owe to the market. Of the $10 million remaining exposure as at September 30, 2017, over 95 percent was related to investment grade counterparties.

Fair Hydro Plan

*OPG's role in connection with the Fair Hydro Plan could have reputational impacts on the Company.*

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and its attendant regulations came into force in June, July, and October 2017. **[UPDATE]** The regulations clarify aspects of the structure and program logistics required for ~~OPG, as~~ the Financial Services Manager of the Fair Hydro Plan, which OPG is planning to undertake, to refinance a portion of the Global Adjustment through the Trust. OPG's reputation could potentially be adversely impacted through its involvement with the Fair Hydro Plan and through stakeholder opinions related to this involvement.

**Commented [A12]:** Not sure this is the right wording. OPG's role as FSM is required under the Act, but not the refinancing through the Trust – the OPG Financing Entity's (or entities) role is discretionary.

OPG – please see changes to this paragraph as follows:

The *Ontario Fair Hydro Plan Act, 2017* received Royal Assent on June 1, 2017 and the associated general regulation came into force in June 2017. As the Financial Services Manager of the Fair Hydro Plan, OPG's reputation could potentially be adversely impacted through this involvement and through stakeholder opinions related to this involvement.

Recovery of Pension and OPEB Costs

On September 14, 2017, the OEB issued its final report on the guiding principles and the policy for recovery mechanisms of pension and OPEB costs of rate regulated utilities in the electricity and natural gas sectors. The report reaffirmed the conclusions of the initial report issued in May 2017, including the establishment of the accrual basis of accounting as the default rate-setting method and the establishment of a variance account to record asymmetric carrying charges in favour of ratepayers on the differences between the accrual costs recovered and cash payments made by a utility for pension and OPEB plans. The report requires OPG to continue to record differences between pension and OPEB accrual costs and cash payments in the Pension & OPEB Cash Versus Accrual Differential Deferral Account that has been in effect since November 1, 2014, until such time as the OEB approves the resumption of the accrual basis of recovery. The future recovery of amounts recorded in the account will be subject to this approval. The report confirmed that OPG would become subject to the carrying charges on the differences between accrual costs and cash payments going back to November 1, 2014, with the charges calculated on the portion of such differences that have been recovered through regulated prices. The carrying charges will be determined at prescribed interest rate set quarterly by the OEB based on the quarterly return of a mid-term corporate bond index yield. This outcome has reduced OPG's risk related to the recovery of actual pension and OPEB accrual

costs and the recovery of the balance in the Pension & OPEB Cash Versus Accrual Differential Deferral Account. The account had a balance of $552 million as at September 30, 2017 and is recognized on the Company's consolidated balance sheet as a regulatory asset. OPG's financial results for the three and nine month periods ended September 30, 2017 were not impacted by the issuance of the OEB's report.

**RELATED PARTY TRANSACTIONS**

Given that the Province owns all of the shares of OPG, related parties include the Province and other entities controlled by the Province.

The related party transactions summarized below include transactions with the Province and the principal successors to the former Ontario Hydro's integrated electricity business, including Hydro One, the IESO and the OEFC. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties. As one of several wholly owned government business enterprises of the Province, OPG also has transactions in the normal course of business with various government ministries and organizations in Ontario that fall under the purview of the Province.

The related party transactions are summarized below:

| | Three Months Ended September 30 | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| *(millions of dollars) (unaudited)* | **Revenue** | **Expense** | **Revenue** | **Expense** |
| Hydro One | | | | |
| Electricity sales | **2** | **-** | 1 | - |
| Services | **-** | **3** | - | 3 |
| Dividends | **2** | **-** | - | 2 |
| Province of Ontario | | | | |
| Decommissioning Fund excess funding [1] | **-** | **(44)** | - | 201 |
| Used Fuel Fund rate of return guarantee and excess funding [1] | **-** | **(39)** | - | 295 |
| Gross revenue charges | **-** | **27** | - | 28 |
| ONFA guarantee fee | **-** | **2** | - | 2 |
| Other | **-** | **2** | - | - |
| OEFC | | | | |
| Gross revenue charges | **-** | **62** | - | 57 |
| Interest expense on long-term notes | **-** | **40** | - | 42 |
| Income taxes, net of investment tax credits | **-** | **23** | - | 28 |
| IESO | | | | |
| Electricity related revenue | **1,126** | **4** | 1,293 | 7 |
| | **1,130** | **80** | 1,294 | 665 |

| (millions of dollars) (unaudited) | Nine Months Ended September 30 2017 Revenue | 2017 Expense | 2016 Revenue | 2016 Expense |
|---|---|---|---|---|
| Hydro One | | | | |
| Electricity sales | **7** | **-** | 4 | - |
| Services | **1** | **8** | 1 | 12 |
| Dividends | **6** | **-** | - | 4 |
| Province of Ontario | | | | |
| Decommissioning Fund excess funding [1] | **-** | **164** | - | 137 |
| Used Fuel Fund rate of return guarantee and excess funding [1] | **-** | **217** | - | 190 |
| Gross revenue charges | **-** | **84** | - | 91 |
| ONFA guarantee fee | **-** | **6** | - | 6 |
| Other | **-** | **3** | - | - |
| OEFC | | | | |
| Gross revenue charges | **-** | **156** | - | 147 |
| Interest expense on long-term notes | **-** | **122** | - | 127 |
| Income taxes, net of investment tax credits | **-** | **132** | - | 112 |
| IESO | | | | |
| Electricity related revenue | **3,228** | **11** | 3,894 | 22 |
| | **3,242** | **903** | 3,899 | 848 |

[1] The Nuclear Segregated Funds are reported on the consolidated balance sheets net of amounts recognized as due to the Province in respect of excess funding and, for the Used Fuel Segregated Fund, the Province's rate of return guarantee. As at September 30, 2017 and December 31, 2016, the Nuclear Segregated Funds were reported net of amounts due to the Province of $3,796 million and $3,415 million, respectively. The details of accounting for the Nuclear Segregated Funds are described in OPG's 2016 annual MD&A in the section, *Critical Accounting Policies and Estimates* under the heading, *Nuclear Fixed Asset Removal and Nuclear Waste Management Funds*.

The receivable, available-for-sale securities, payable and long-term debt balances between OPG and its related parties are summarized below:

| (millions of dollars) (unaudited) | September 30 2017 | December 31 2016 |
|---|---|---|
| Receivables from related parties | | |
| Hydro One | **1** | 1 |
| IESO | **346** | 421 |
| OEFC | **3** | 1 |
| PEC | **2** | 4 |
| Province of Ontario | **5** | 2 |
| Available-for-sale securities | | |
| Hydro One shares | **190** | 212 |
| Accounts payable and accrued charges | | |
| OEFC | **37** | 61 |
| Province of Ontario | **6** | 2 |
| IESO | **2** | 2 |
| Long-term debt (including current portion) | | |
| Notes payable to OEFC | **3,245** | 3,295 |

OPG holds interest-bearing Province of Ontario bonds in the Nuclear Segregated Funds and the OPG registered pension fund. As at September 30, 2017, the Nuclear Segregated Funds held $1,498 million of interest-bearing Province of Ontario bonds, while the registered pension fund had no such holdings. As at December 31, 2016, the Nuclear Segregated Funds and the registered pension fund held $1,652 million and $284 million of interest-bearing Province of Ontario bonds, respectively. These bonds are publicly traded securities and are measured at fair value. OPG jointly oversees the investment management of the Nuclear Segregated Funds with the Province.

There have been no related party transactions related to the Fair Hydro Plan and associated financing activities. The first transaction between the Trust and the IESO is expected later in 2017.

## INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

The Company maintains a comprehensive system of policies, procedures, and processes that represents its framework for internal controls over financial reporting and for its disclosure controls and procedures (together, ICOFR). There were no changes in the Company's internal control system during the current interim period that has or is reasonably likely to have a material impact to the ICOFR.

## QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters.

| *(millions of dollars - except where noted) (unaudited)* | **September 30 2017** | **June 30 2017** | **March 31 2017** | **December 31 2016** |
|---|---|---|---|---|
| Revenue | **1,217** | 1,146 | 1,176 | 1,388 |
| Net income (loss) | **140** | 307 | 68 | (8) |
| Less: Net income attributable to non-controlling interest | **9** | 4 | 4 | 5 |
| Net income (loss) attributable to the Shareholder | **131** | 303 | 64 | (13) |
| **Per common share, attributable to the Shareholder *(dollars)*** | **$0.51** | $1.18 | $0.25 | ($0.05) |

| *(millions of dollars - except where noted) (unaudited)* | **September 30 2016** | **June 30 2016** | **March 31 2016** | **December 31 2015** |
|---|---|---|---|---|
| Revenue | 1,400 | 1,387 | 1,478 | 1,312 |
| Net income (loss) | 198 | 135 | 128 | (100) |
| Less: Net income attribute to the non-controlling interest | 4 | 3 | 5 | 1 |
| Net income (loss) attributable to the Shareholder | 194 | 132 | 123 | (101) |
| **Per common share, attributable to the Shareholder *(dollars)*** | $0.76 | $0.51 | $0.48 | ($0.39) |

### Trends

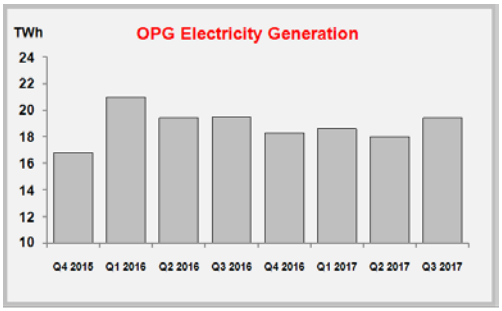
OPG's quarterly results are affected by changes in grid-supplied electricity demand, primarily resulting from variations in seasonal weather conditions, changes in economic conditions, the impact of small scale generation embedded in distribution networks, and the impact of conservation efforts in the province. Weather conditions affect water flows, electricity demand, and prevalence of SBG conditions. Historically, OPG's revenues have been higher in the first

quarter of a fiscal year as a result of winter heating demands and in the third quarter due to air conditioning and cooling demands. The financial impact of forgone production due to SBG conditions at the regulated hydroelectric stations and the financial impact of differences between forecast water flows reflected in OEB-approved regulated prices and the actual water flows are mitigated by regulatory variance accounts authorized by the OEB.

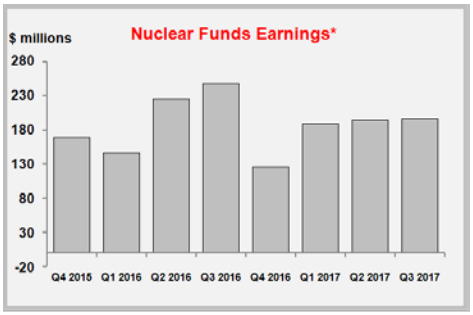
The timing of planned outages at a nuclear generating station during the year can cause variability in year-over-year operating results for partial periods of a fiscal year, including the impact on revenue and OM&A expenses, but is not a significant driver of variability for full fiscal year results.

OPG's electricity generation was reduced as a result of the Unit 2 refurbishment outage at the Darlington GS, which began in October 2016 and is expected to continue until early 2020.

OPG's financial results are also affected by the earnings on the Nuclear Segregated Funds, net of the impact of the Bruce Lease Net Revenues Variance Account.




Additional items that affected net income in certain quarters above are described in OPG's 2016 annual MD&A under




*net of regulatory variance account

the section, *Quarterly Financial Highlights*.

**SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES**

In addition to providing net income and other financial information in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP and, therefore, may not be comparable to similar measures presented by other issuers. OPG utilizes these measures to make operating decisions and assess performance. Readers of the MD&A would utilize these measures in assessing the Company's financial performance from ongoing operations. The Company believes that these indicators are important since they provide additional information about OPG's performance, facilitate comparison of results over different periods, and present measures consistent with the Company's strategies to provide value to the Shareholder, improve cost performance, and ensure availability of cost effective funding. These non-GAAP financial measures have not been presented as an alternative to net income, cash flow provided by operating activities, or any other measure in accordance with US GAAP, but as indicators of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE Excluding AOCI** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCI, for the period. ROE Excluding AOCI is measured over a 12-month period and is calculated as follows:

| | **Twelve Months Ended** | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **September 30 2017** | **December 31 2016** |
| ROE Excluding AOCI | | |
| Net income attributable to the Shareholder | **485** | 436 |
| Divided by: Average equity attributable to the Shareholder, excluding AOCI | **11,055** | 10,442 |
| **ROE Excluding AOCI *(percent)*** | **4.4** | 4.2 |

(2) **FFO Adjusted Interest Coverage** is defined as FFO before interest divided by adjusted interest expense. FFO before interest is defined as cash flow provided by operating activities adjusted for interest paid, interest capitalized to fixed and intangible assets, and changes to non-cash working capital balances for the period. Adjusted interest expense is calculated as net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and the excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets, for the period.

FFO Adjusted Interest Coverage is measured over a 12-month period and is calculated as follows:

| | Twelve Months Ended | |
|---|---|---|
| *(millions of dollars – except where noted) (unaudited)* | **September 30 2017** | **December 31 2016** |
| FFO before interest | | |
| Cash flow provided by operating activities | **1,082** | 1,595 |
| Add: Interest paid | **270** | 269 |
| Less: Interest capitalized to fixed and intangible assets | **(161)** | (141) |
| Less: Changes to non-cash working capital balances | **38** | 42 |
| FFO before interest | **1,229** | 1,765 |
| Adjusted interest expense | | |
| Net interest expense | **84** | 120 |
| Add: Interest income | **8** | 7 |
| Add: Interest capitalized to fixed and intangible assets | **161** | 141 |
| Add: Interest related to regulatory assets and liabilities | **43** | 30 |
| Add: Excess of interest on pension and OPEB projected benefit obligations over expected return on pension plan assets [1] | **-** | 45 |
| Adjusted interest expense | **296** | 343 |
| **FFO Adjusted Interest Coverage** *(times)* | **4.2** | 5.1 |

[1] A value of nil is used in the calculation when interest on pension and OPEB projected benefit obligations is equal to, or lower than, expected return on pension plan assets.

(3) **Enterprise Total Generating Cost per MWh** is used to measure OPG's overall organizational cost performance. Enterprise TGC per MWh is defined as OM&A expenses (excluding the Darlington Refurbishment project and other generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to OPG's electricity generation business), fuel expense for OPG-operated stations including hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures (excluding the Darlington Refurbishment project and other generation development projects) incurred during the period, divided by total electricity generation from OPG-operated generating stations plus electricity generation forgone due to SBG conditions during the period.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Enterprise TGC | | | | |
| Total OM&A expenses | **635** | 666 | **2,054** | 2,061 |
| Total fuel expense | **185** | 187 | **518** | 541 |
| Total capital expenditures | **476** | 444 | **1,335** | 1,162 |
| Less: Darlington Refurbishment capital and OM&A costs | **(328)** | (269) | **(943)** | (717) |
| Less: Other generation development project capital and OM&A costs | **(17)** | (42) | **(53)** | (121) |
| Add (Less): OM&A and fuel expenses (refundable through) deferred in regulatory variance and deferral accounts | **4** | 35 | **(19)** | 76 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(13)** | (18) | **(42)** | (50) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **13** | 5 | **47** | 38 |
| Less: OM&A expenses ancillary to electricity generation business | **(4)** | (5) | **(13)** | (17) |
| Other adjustments | **(3)** | (12) | **(7)** | (15) |
| | **948** | 991 | **2,877** | 2,958 |
| Adjusted electricity generation *(TWh)* | | | | |
| Total OPG electricity generation | **19.4** | 19.5 | **56.0** | 59.9 |
| Adjust for electricity generation forgone due to SBG conditions and OPG's share of electricity generation from co-owned facilities | **0.9** | 0.1 | **4.2** | 3.4 |
| | **20.3** | 19.6 | **60.2** | 63.3 |
| **Enterprise TGC per MWh *($/MWh)*** [1] | **46.65** | 50.72 | **47.77** | 46.74 |

[1] Amounts may not calculate due to rounding.

(4) **Nuclear Total Generating Cost per MWh** is used to measure the cost performance of OPG's nuclear generating assets. Nuclear TGC per MWh is defined as OM&A expenses of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the nuclear electricity generation business), nuclear fuel expense for OPG-operated stations (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Nuclear Generation segment (excluding the Darlington Refurbishment project costs) incurred during the period, divided by nuclear electricity generation for the period.

| *(millions of dollars – except where noted) (unaudited)* | Three Months Ended September 30 | | Nine Months Ended September 30 | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Nuclear TGC | | | | |
| Regulated – Nuclear Generation OM&A expenses | **511** | 521 | **1,693** | 1,665 |
| Regulated – Nuclear Generation fuel expense | **81** | 79 | **217** | 239 |
| Regulated – Nuclear Generation capital expenditures | **409** | 339 | **1,150** | 896 |
| Less: Darlington Refurbishment capital and OM&A costs | **(328)** | (269) | **(943)** | (717) |
| Add: Regulated – Nuclear Generation OM&A and fuel expenses deferred in regulatory variance and deferral accounts | **5** | 31 | **6** | 84 |
| Less: Nuclear fuel expense for non OPG-operated stations | **(13)** | (18) | **(42)** | (50) |
| Less: Regulated - Nuclear Generation OM&A expenses ancillary to nuclear electricity generation business | **(1)** | (1) | **(3)** | (4) |
| Other adjustments | **1** | 3 | **(1)** | (1) |
| | **665** | 685 | **2,077** | 2,112 |
| Nuclear electricity generation (TWh) | **11.3** | 11.7 | **30.6** | 34.6 |
| **Nuclear TGC per MWh (*$/MWh*)** [1] | **58.75** | 58.55 | **67.87** | 61.07 |

[1] Amounts may not calculate due to rounding.

(5) **Hydroelectric Total Generating Cost per MWh** is used to measure the cost performance of OPG's hydroelectric generating assets. Hydroelectric TGC per MWh is defined as OM&A expenses of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding generation development project costs, the impact of regulatory variance and deferral accounts, and expenses ancillary to the hydroelectric electricity generation business), hydroelectric gross revenue charge and water rental payments (excluding the impact of regulatory variance and deferral accounts), and capital expenditures of the Regulated – Hydroelectric segment and the hydroelectric facilities included in the Contracted Generation Portfolio segment (excluding expenditures related to the Peter Sutherland Sr. GS, Ranney Falls GS, and other hydroelectric generation development projects) incurred during the period, divided by total hydroelectric electricity generation plus hydroelectric electricity generation forgone due to SBG conditions during the period. OPG reports hydroelectric gross revenue charge and water rental payments as fuel expense.

| *(millions of dollars – except where noted) (unaudited)* | **Three Months Ended September 30** | | **Nine Months Ended September 30** | |
|---|---|---|---|---|
| | **2017** | **2016** | **2017** | **2016** |
| Hydroelectric TGC | | | | |
| Regulated – Hydroelectric OM&A expenses | **81** | 87 | **232** | 238 |
| Regulated – Hydroelectric fuel expense | **88** | 88 | **258** | 259 |
| Contracted Generation Portfolio OM&A expenses | **39** | 44 | **118** | 129 |
| Contracted Generation Portfolio fuel expense | **15** | 19 | **42** | 42 |
| Regulated – Hydroelectric and Contracted Generation Portfolio capital expenditures | **56** | 92 | **141** | 231 |
| Less: Regulated – Hydroelectric and Contracted Generation Portfolio generation development project capital and OM&A costs | **(17)** | (41) | **(52)** | (117) |
| Less: Thermal OM&A and fuel expenses and capital expenditures in the Contracted Generation Portfolio | **(39)** | (51) | **(119)** | (126) |
| (Less) Add: Regulated – Hydroelectric OM&A and fuel expenses refundable through regulatory variance and deferral accounts | **(1)** | 4 | **(25)** | (8) |
| Add: Hydroelectric gross revenue charge and water rental payments for electricity generation forgone due to SBG conditions | **13** | 5 | **47** | 38 |
| Other adjustments | **(1)** | (1) | **-** | (1) |
| | **234** | 246 | **642** | 685 |
| Adjusted hydroelectric electricity generation *(TWh)* | | | | |
| Regulated – Hydroelectric electricity generation | **7.3** | 6.9 | **23.5** | 22.8 |
| Contracted Generation Portfolio electricity generation | **0.8** | 0.9 | **1.9** | 2.5 |
| Adjust for hydroelectric electricity generation forgone due to SBG conditions and non-hydroelectric electricity generation of the Contracted Generation Portfolio, including OPG's share of electricity generation from co-owned facilities | **0.8** | 0.1 | **4.1** | 3.4 |
| | **8.9** | 7.9 | **29.5** | 28.7 |
| **Hydroelectric TGC per MWh *($/MWh)*** [1] | **26.20** | 31.01 | **21.74** | 23.99 |

[1] Amounts may not calculate due to rounding.

(6) **Gross margin** is defined as revenue less fuel expense.

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XRF: FIN5167DM-2018-15

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| | | | |
|---|---|---|---|
| **Date** | April 23, 2018 | | |
| **From** | Brett Saulnier | **Direct Tel** | 416-865-8148 |
| **Page(s)** | 30 (including this cover page) | | 39953-2002 |

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| Ministry of Energy (Minister) | (416) 327-6754 | |
| Ministry of Energy (Deputy) | (416) 327-6755 | |

**Comments** See attached

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April 23, 2018

**CONFIDENTIAL**

Ministry of Finance
7 Queen's Park Crescent, 7th Floor
Toronto, Ontario M7A 1Y7

**Attention:** Minister of Finance
Deputy Minister of Finance

Ministry of Energy
Hearst Block 4th Floor, 900 Bay Street
Toronto, Ontario M7A 2E1

**Attention:** Minister of Energy
Deputy Ministry of Energy

Dear Sirs/Mesdames:

**Re: Fair Hydro Plan – Deliveries under Change of Law Process Agreement**

Reference is made to the Change of Law Process Agreement dated as of December 21, 2017 between Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance, and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have their respective meanings in the Change of Law Process Agreement.

On April 24, Fair Hydro Trust (the "**Issuer**") will issue (i) C$400,000,000 aggregate principal amount of 3.52% Senior Notes due May 15, 2038, Series 2018-2 in accordance with the terms of an agency agreement dated as of April 19, 2018 among the Issuer, Ontario Power Generation Inc. ("**OPG**") and the dealers named therein, (ii) C$305,882,000 aggregate principal amount of 3.834% Subordinated Notes due May 15, 2038, Series 2018-2 and (iii) C$78,431,000 aggregate principal amount of 4.214% Junior Subordinated Notes due May 15, 2038, Series 2018-2 (collectively, the "**Funding Obligations**").

On behalf of Ontario Power Generation Inc. and pursuant to section 3.01 of the Change of Law Process Agreement, please find enclosed a Process Certificate in respect of the Funding Obligations.

On behalf of Ontario Power Generation Inc. and pursuant to section 2.01(c) of the Change of Law Process Agreement, please find enclosed one Special Payment Date Agreement in respect of each of the Warehouse Senior Series 2017-1 Supplemental Indenture dated as of December 21, 2017 among, *inter alios*, the Issuer, Royal Bank of Canada and BNY Trust Company of Canada (the "**Indenture Trustee**"), the Warehouse Subordinated Series 2017-1 Supplemental

Indenture dated as of December 21, 2017 among the Issuer, OPG and the Indenture Trustee and the Warehouse Junior Subordinated Series 2017-1 Supplemental Indenture dated as of December 21, 2017 among the Issuer, OPG and the Indenture Trustee (collectively, the "**Warehouse Facilities**"). Such Special Payment Date Agreements permit a partial repayment of the Warehouse Facilities using proceeds from the Funding Obligations on a date that is not the 15th day of a given calendar month and allow the decrease notice to be delivered within two business days of such repayment (rather than five business days).

Yours truly,



Brett Saulnier

Encl.

cc: Rima Ramchandani, *Torys LLP*
John Lee, *Ontario Power Generation Inc.*
Lubna Ladak, *Ontario Power Generation Inc.*
Clara Greco, *Ontario Power Generation Inc.*

25407780.3

**ONTARIO POWER GENERATION INC.,**
**in its capacity as FSM**

**PROCESS CERTIFICATE (2018-2)**

*Certificate of the CFO and Treasurer pursuant to section 3.01 of the Change of Law Process Agreement*

**TO:** Her Majesty the Queen in Right of Ontario, as represented by the Minister of Energy and the Minister of Finance (the "**Province**")

**RE:** C$400,000,000 aggregate principal amount of 3.52% Senior Notes due May 15, 2038, Series 2018-2 (the "**Series 2018-2 Senior Notes**")

**AND RE:** C$305,882,000 aggregate principal amount of 3.834% Subordinated Notes due May 15, 2038, Series 2018-2 (the "**Series 2018-2 Subordinated Notes**")

**AND RE:** C$78,431,000 aggregate principal amount of 4.214% Junior Subordinated Notes due May 15, 2038, Series 2018-2 (the "**Series 2018-2 Junior Subordinated Notes**")

**AND RE:** Agency agreement between Fair Hydro Trust (the "**Issuer**"), Ontario Power Generation Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., Goldman Sachs Canada Inc., BMO Nesbitt Burns Inc., Scotia Capital Inc., National Bank Financial Inc., TD Securities Inc., Morgan Stanley Canada Limited, HSBC Securities (Canada) Inc., Laurentian Bank Securities Inc., Desjardins Securities Inc. and Casgrain & Company Limited dated as of April 19, 2018 (the "**Agency Agreement**" and together with the Series 2018-2 Senior Notes, the Series 2018-2 Subordinated Notes and the Series 2018-2 Junior Subordinated Notes, the "**Funding Obligations**")

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Reference is made to the Change of Law Process Agreement dated December 21, 2017 among the Province and Ontario Power Generation Inc. (the "**Change of Law Process Agreement**"). Capitalized terms used and not defined herein shall have the meanings ascribed to such terms in the Change of Law Process Agreement.

Each of the undersigned, being the Chief Financial Officer and Treasurer of OPG acting in its capacity as FSM and holding the offices set forth under their names and signatures below, pursuant to and accordance with section 3.01 of the Change of Law Process Agreement, hereby certifies for and on behalf of OPG, in its capacity as Financial Services Manager, and not in such officer's personal capacity and intending that this certificate may be relied on by the addressees hereof without independent inquiry, that:

1. I have read and understand the provisions of the Change of Law Process Agreement and all other documents and materials necessary to enable me to deliver this certificate.

2. The material terms of the Series 2018-2 Senior Notes are set forth in Schedule A.

3. The material terms of the Series 2018-2 Subordinated Notes are set forth in Schedule B.

4. The material terms of the Series 2018-2 Junior Subordinated Notes are set forth in Schedule C.

5. The material terms of the Agency Agreement are set forth in Schedule D.

6. The Funding Obligations:

   (a) will arise under terms and conditions that are Substantially in the Form of the Reference Documentation applicable thereto;

   (b) in my opinion, are reasonably incurred or effected in compliance with the Act, the General Regulation, any other enactments related thereto and the Financing Plan;

   (c) are of a type and are on terms that a reasonably prudent financial services manager would incur in similar circumstances; and

   (d) reflect, in all material respects, arm's length terms and conditions.

7. The Disclosure Document used in connection with the offering and sale of the Series 2018-2 Senior Notes is Substantially in the Form of the Reference Documentation. No Disclosure Document was used in connection with the offering and sale of the Series 2018-2 Subordinated Notes or Series 2018-2 Junior Subordinated Notes.

8. Any disclosure made in respect of any of the Funding Obligations (including any Disclosure Document, press release or other written communication prepared for dissemination to third parties in relation to any of the Funding Obligations) that refers to or describes the terms, effect or adherence of or to the Change of Law Process Agreement or the Change of Law Protection Agreement has been made available to the Province prior to use or dissemination, other than where such disclosure was substantially the same as a disclosure previously made.

9. No Breach Event has occurred on or prior to the date hereof, unless such Breach Event has been waived by the Province in writing.

10. At the time the Funding Obligations are incurred, the maximum aggregate payment amounts due or becoming due in the future in respect of Repayments under the Funding Obligations, together with all other outstanding amounts due or becoming due in the future in respect of Repayments under all Approved Obligations, do not exceed the Protection Agreement Maximum applicable on the date hereof.

***[Remainder of page intentionally left blank.]***

**DATED** as of the 24th day of April, 2018.

Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

Name: John Lee
Title: Vice President – Treasurer

*[Signature page to Process Certificate (2018-2)]*

# SCHEDULE A

| SERIES 2018-2 SENIOR NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$400,000,000 |
| Interest Rate | 3.52% per annum (the "Series 2018-2 Senior Interest Rate") |
| Interest Payments | The "Interest Payment Dates" for the Series 2018-2 Senior Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-2 Senior Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-2 Senior Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "MTI")) thereafter at a rate equal to the monthly equivalent of the Series 2018-2 Senior Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-2 Senior Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-2 Senior Notes will include accrued and unpaid interest for the period from, and including, April 24, 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$2.02520548 per C$1,000 principal amount of Series 2018-2 Senior Notes.<br><br>"Amortization Event" means either an Acceleration Event has occurred with respect to the Series 2018-2 Senior Notes, or the outstanding principal amount of the Series 2018-2 Senior Notes has not been paid in full on May 15, 2038.<br><br>"Acceleration Event" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-2 Senior Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000.02 per C$1,000 principal amount of Series 2018-2 Senior Notes |
| Fees | See Schedule D under the heading "Fees" |
| Term to Maturity | 20 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-2 Senior Notes shall be due and payable on May 15, 2038. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-2 Senior Notes and the then outstanding principal amount of the Series 2018-2 Senior Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2038 for the Series 2018-2 Senior Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-2 Senior Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-2 Senior Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-2 Senior Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix I hereto. |
| Extension | N/A |
| Redemption | The Series 2018-2 Senior Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-2 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"Par Call Date" means November 15, 2037.<br><br>"Series 2018-2 Canada Yield Price" means a price equal to the price of the Series 2018-2 Senior Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.265% per annum.<br><br>"Government of Canada Yield" on any date means, in respect of the Series 2018-2 Senior Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 1

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| June 15, 2037 | C$33,333,333.33 |
| July 15, 2037 | C$33,333,333.33 |
| August 15, 2037 | C$33,333,333.33 |
| September 15, 2037 | C$33,333,333.33 |
| October 15, 2037 | C$33,333,333.33 |
| November 15, 2037 | C$33,333,333.33 |
| December 15, 2037 | C$33,333,333.33 |
| January 15, 2038 | C$33,333,333.33 |
| February 15, 2038 | C$33,333,333.33 |
| March 15, 2038 | C$33,333,333.33 |
| April 15, 2038 | C$33,333,333.33 |
| May 15, 2038 | C$33,333,333.37 |

# SCHEDULE B

| SERIES 2018-2 SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$305,882,000 |
| Interest Rate | 3.834% per annum (the "**Series 2018-2 Subordinated Interest Rate**") |
| Interest Payments | The "**Interest Payment Dates**" for the Series 2018-2 Subordinated Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-2 Subordinated Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-2 Subordinated Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "**MTI**")) thereafter at a rate equal to the monthly equivalent of the Series 2018-2 Subordinated Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-2 Subordinated Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-2 Subordinated Notes will include accrued and unpaid interest for the period from, and including, April 24 , 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$2.20586301 per C$1,000 principal amount of Series 2018-2 Subordinated Notes.<br><br>"**Amortization Event**" means either an Acceleration Event has occurred with respect to the Series 2018-2 Subordinated Notes, or the outstanding principal amount of the Series 2018-2 Subordinated Notes has not been paid in full on May 15, 2038.<br><br>"**Acceleration Event**" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-2 Subordinated Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000 per C$1,000 principal amount of Series 2018-2 Subordinated Notes |
| Fees | N/A |
| Term to Maturity | 20 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-2 Subordinated Notes shall be due and payable on May 15, 2038. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-2 Subordinated Notes and the then outstanding principal amount of the Series 2018-2 Subordinated Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2038 for the Series 2018-2 Subordinated Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-2 Subordinated Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-2 Subordinated Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-2 Subordinated Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix 2 hereto. |
| Extension | N/A |
| Redemption | The Series 2018-2 Subordinated Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-2 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"**Par Call Date**" means November 15, 2037.<br><br>"**Series 2018-2 Canada Yield Price**" means a price equal to the price of the Series 2018-2 Subordinated Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.345% per annum.<br><br>"**Government of Canada Yield**" on any date means, in respect of the Series 2018-2 Subordinated Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 2

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| June 15, 2037 | C$25,490,166.67 |
| July 15, 2037 | C$25,490,166.67 |
| August 15, 2037 | C$25,490,166.67 |
| September 15, 2037 | C$25,490,166.67 |
| October 15, 2037 | C$25,490,166.67 |
| November 15, 2037 | C$25,490,166.67 |
| December 15, 2037 | C$25,490,166.67 |
| January 15, 2038 | C$25,490,166.67 |
| February 15, 2038 | C$25,490,166.67 |
| March 15, 2038 | C$25,490,166.67 |
| April 15, 2038 | C$25,490,166.67 |
| May 15, 2038 | C$25,490,166.63 |

# SCHEDULE C

| SERIES 2018-2 JUNIOR SUBORDINATED NOTES TERM SHEET | |
|---|---|
| Principal Amount | Unlimited but initially C$78,431,000 |
| Interest Rate | 4.214% per annum (the "Series 2018-2 Junior Subordinated Interest Rate") |
| Interest Payments | The "Interest Payment Dates" for the Series 2018-2 Junior Subordinated Notes are as follows: (i) prior to the occurrence of an Amortization Event (as defined below), interest on the Series 2018-2 Junior Subordinated Notes shall be payable in equal semi-annual instalments (except the first interest payment) in arrears on May 15 and November 15 of each year, commencing May 15, 2018 (short first coupon); and (ii) following the occurrence of an Amortization Event, interest will be payable in arrears on the outstanding principal amount of the Series 2018-2 Junior Subordinated Notes on each Payment Date (as defined in the Master Trust Indenture dated December 21, 2017 between the Issuer and BNY Trust Company of Canada, as supplemented (the "MTI")) thereafter at a rate equal to the monthly equivalent of the Series 2018-2 Junior Subordinated Interest Rate; that is, the interest rate that, when compounded monthly for six months on a stated outstanding principal amount, yields interest in an amount equal to the Series 2018-2 Junior Subordinated Interest Rate, multiplied by such outstanding principal amount and divided by two.<br><br>The first interest payment on the Series 2018-2 Junior Subordinated Notes will include accrued and unpaid interest for the period from, and including, April 24, 2018 to, but excluding, the first Interest Payment Date. Subject to the occurrence of an Acceleration Event (as defined below), the first interest payment will be in an amount equal to C$2.424493.15 per C$1,000 principal amount of Series 2018-2 Junior Subordinated Notes.<br><br>"Amortization Event" means either an Acceleration Event has occurred with respect to the Series 2018-2 Junior Subordinated Notes, or the outstanding principal amount of the Series 2018-2 Junior Subordinated Notes has not been paid in full on May 15, 2038.<br><br>"Acceleration Event" means either (i) all Issuer Funding Obligations are declared due and payable in accordance with the provisions of the MTI, or (ii) the outstanding principal amount of the Series 2018-2 Junior Subordinated Notes and all interest thereon is declared due and payable in accordance with the MTI as a result of the occurrence of certain events of default. |
| Issue Price | C$1,000 per C$1,000 principal amount of Series 2018-2 Junior Subordinated Notes |
| Fees | N/A |
| Term to Maturity | 20 years |
| Amortization | Subject to the occurrence of an Acceleration Event, the outstanding principal amount of the Series 2018-2 Junior Subordinated Notes shall be due and payable on May 15, 2038. Following the occurrence of an Amortization Event, each Payment Date thereafter shall be a Principal Payment Date (as defined in the MTI) in respect of the Series 2018-2 Junior Subordinated Notes and the then outstanding principal amount of the Series 2018-2 Junior Subordinated Notes shall be due and payable on each such Payment Date. A failure to pay principal on May 15, 2038 for the Series 2018-2 Junior Subordinated Notes will constitute an event of default upon the occurrence of which the holders of Series 2018-2 Junior Subordinated Notes may declare the outstanding principal and all accrued and unpaid interest on the Series 2018-2 Junior Subordinated Notes to be immediately due and payable.<br><br>Subject to the occurrence of an Amortization Event, the Series 2018-2 Junior Subordinated Notes shall have the Principal Accumulation Amounts for the Payment Dates specified in Appendix 3 hereto. |
| Extension | N/A |
| Redemption | The Series 2018-2 Junior Subordinated Notes will be redeemable at the option of the Issuer, in whole or in part, at any time and from time to time, on not less than 15 nor more than 60 days' notice at the redemption price specified below. At any time prior to the Par Call Date (as defined below), the redemption price will be equal to the greater of (i) the Series 2018-2 Canada Yield Price (as defined below) and (ii) par, plus, in each case, accrued and unpaid interest to, but not including, the date of redemption. On or after the Par Call Date, the redemption price will be equal to par, plus accrued and unpaid interest to, but not including, the date of redemption.<br><br>"Par Call Date" means November 15, 2037.<br><br>"Series 2018-2 Canada Yield Price" means a price equal to the price of the Series 2018-2 Junior Subordinated Notes calculated to provide a yield to the Par Call Date, compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, equal to the Government of Canada Yield (as defined below) calculated at 10:00 a.m. (Toronto time) on the third business day preceding the date of redemption, plus 0.440% per annum.<br><br>"Government of Canada Yield" on any date means, in respect of the Series 2018-2 Junior Subordinated Notes being redeemed, the yield from the redemption date to the Par Call Date compounded semi-annually and calculated in accordance with generally accepted Canadian financial practice, which a non-callable Government of Canada bond would carry if issued in Canadian dollars in Canada at 100% of its principal amount on such date with a term to maturity equal to the remaining term to the Par Call Date (calculated from the date of redemption), such yield being the average of the yields provided by two major Canadian investment dealers specified by the Issuer. |

# APPENDIX 3

## PRINCIPAL ACCUMULATION AMOUNTS AND PAYMENT DATES

| Payment Date | Principal Accumulation Amount |
|---|---|
| June 15, 2037 | C$6,535,916.67 |
| July 15, 2037 | C$6,535,916.67 |
| August 15, 2037 | C$6,535,916.67 |
| September 15, 2037 | C$6,535,916.67 |
| October 15, 2037 | C$6,535,916.67 |
| November 15, 2037 | C$6,535,916.67 |
| December 15, 2037 | C$6,535,916.67 |
| January 15, 2038 | C$6,535,916.67 |
| February 15, 2038 | C$6,535,916.67 |
| March 15, 2038 | C$6,535,916.67 |
| April 15, 2038 | C$6,535,916.67 |
| May 15, 2038 | C$6,535,916.63 |

# SCHEDULE D

| AGENCY AGREEMENT TERMS | |
|---|---|
| Appointment | The Issuer appoints the Agents to act as its sole and exclusive agents to effect the solicitation and private placement of Series 2018-2 Senior Notes to "accredited investors", as such term is defined under applicable securities laws, in the Provinces of Canada (the "Offering"). |
| Fees | In consideration of the services provided to the Issuer by the Agents, the Issuer agrees to pay the Agents a fee equal to 0.55% of the aggregate principal amount of Series 2018-2 Senior Notes sold in the Offering. |
| Representations and Warranties | Representations and warranties in favour of the Agents from each of the Issuer and OPG customary for a private placement of notes, including representations that the disclosure document used in connection with the Offering does not contain a "misrepresentation", as such term is defined under applicable securities laws. |
| Conditions to Closing | As conditions to the closing of the Offering, the Issuer must provide, or arrange to have provided, certain standard certificates, legal opinions and other deliverables to the Agents. |
| Termination | The Agents have customary rights to terminate their obligations on the occurrence of certain events, including legal or other proceedings resulting in a material adverse change, a material adverse change in respect of the Issuer and financial disasters. |
| Indemnity | Each of the Issuer and OPG provides an indemnity to each of the Agents for any losses resulting from, among other things, breaches of representations, warranties and covenants, breaches of securities laws or a "misrepresentation" in the disclosure document used in connection with the Offering. |

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT (2018-2)
## (Senior Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Senior Series 2017-1 Supplemental Indenture (the "**Senior Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about April 24, 2018 of Senior Notes bearing the full designation "3.52% Senior Notes due May 15, 2038, Series 2018-2" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Senior Warehouse Supplemental Indenture, the date of issuance of the Senior Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Senior Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $400,000,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Senior Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Senior Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Senior Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4(a) of the Senior Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Senior Notes. If the Special Principal Payment Date has not

occurred by May 15, 2018 this Special Principal Payment Date Agreement shall cease to be of any force and effect.

7. Except as modified hereby, the provisions of the Senior Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Each Series 2017-1 Senior Noteholder acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

*[Signature Page Follows]*

DATED this 20th day of April, 2018.

COMPUTERSHARE TRUST COMPANY OF CANADA, in its capacity as trustee of FAIR HYDRO TRUST, as Issuer by ONTARIO POWER GENERATION INC., not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Senior Warehouse]*

S-2

**BNY TRUST COMPANY OF CANADA**, as Indenture Trustee

By: _____
Name: Ahmad Adam
Title: Vice-President

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Senior Warehouse]*

**ROYAL BANK OF CANADA**, as Administrative Agent

By: _____
Name: Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: NUR KHAN
MANAGING DIRECTOR

**CIBC MELLON TRUST COMPANY**, in its capacity as trustee of **LAKESHORE TRUST**, by its Financial Services Agent, **ROYAL BANK OF CANADA**, as a CP Conduit Purchaser

By: _____
Name: Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: NUR KHAN
MANAGING DIRECTOR

**ROYAL BANK OF CANADA**, as a Group Bank

By: _____
Name: Ian Benaiah
Title: Authorized Signatory

By: _____
Name:
Title: NUR KHAN
MANAGING DIRECTOR

**CANADIAN IMPERIAL BANK OF COMMERCE**, as a Group Bank

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **SOUND TRUST**, by its Financial Services Agent, **CANADIAN IMPERIAL BANK OF COMMERCE**, as a CP Conduit Purchaser

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

**COMPUTERSHARE TRUST COMPANY OF CANADA**, in its capacity as trustee of **SURE TRUST**, by its Financial Services Agent, **CANADIAN IMPERIAL BANK OF COMMERCE**, as a CP Conduit Purchaser

By: _____
Name: Andrew Maciel
Title: Authorized Signatory

By: _____
Name: Sunil Adalja
Title: Authorized Signatory

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**GOLDMAN SACHS BANK USA,**
as a Non-Conduit Purchaser

By: _____
Name: Charles D. Johnston
Title: Authorized Signatory

By: _____
Name:
Title:

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Senior Warehouse]*

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT (2018-2)
## (Subordinated Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Subordinated Series 2017-1 Supplemental Indenture (the "**Subordinated Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about April 24, 2018 of Subordinated Notes bearing the full designation "3.834% Subordinated Notes due May 15, 2038, Series 2018-2" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Subordinated Warehouse Supplemental Indenture, the date of issuance of the Subordinated Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Subordinated Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $305,882,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Subordinated Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Subordinated Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Subordinated Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4 of the Subordinated Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Subordinated Notes. If the Special Principal Payment Date has not occurred by May 15, 2018 this Special Principal Payment Date Agreement shall cease to be of any force and effect.

7. Except as modified hereby, the provisions of the Subordinated Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Ontario Power Generation Inc. acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

***[Signature Page Follows]***

DATED this 20th day of April, 2018.

COMPUTERSHARE TRUST COMPANY OF CANADA, in its capacity as trustee of FAIR HYDRO TRUST, as Issuer by ONTARIO POWER GENERATION INC., not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President - Treasurer

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Subordinated Warehouse]*

**BNY TRUST COMPANY OF CANADA**, as Indenture Trustee

By: _____
Name: Ahmad Adam
Title: Vice-President

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Subordinated Warehouse]*

ONTARIO POWER GENERATION INC.

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Subordinated Warehouse]*

# SPECIAL PRINCIPAL PAYMENT DATE AGREEMENT (2018-2)
## (Junior Subordinated Warehouse Supplemental Indenture)

Reference is made to:

(a) the Trust Indenture dated as of December 21, 2017 (the "**Trust Indenture**") between Computershare Trust Company of Canada in its capacity as trustee of Fair Hydro Trust and BNY Trust Company of Canada, as indenture trustee;

(b) the Warehouse Junior Subordinated Series 2017-1 Supplemental Indenture (the "**Junior Subordinated Warehouse Supplemental Indenture**") made as of December 21, 2017 between the undersigned signatories to this Special Principal Payment Date Agreement;

(c) an expected issuance on or about April 24, 2018 of Junior Subordinated Notes bearing the full designation "4.214% Junior Subordinated Notes due May 15, 2033, Series 2018-1" pursuant to a new Supplemental Indenture to be entered into (the "**Expected Term Issuance**").

Terms with initial capital letters in this Special Principal Payment Date Agreement have the meanings given to them in, or for the purposes of, the Senior Warehouse Supplemental Indenture and the Trust Indenture.

The undersigned hereby agree as follows:

1. Notwithstanding the terms of the Junior Subordinated Warehouse Supplemental Indenture, the date of issuance of the Junior Subordinated Notes pursuant to the Expected Term Issuance (the "**Special Principal Payment Date**") will be a Principal Payment Date and a Decrease Date as such terms are defined under, and for the purposes of, the Junior Subordinated Warehouse Supplemental Indenture.

2. Each of the Principal Payment Amount and the Decrease Amount for such Special Principal Payment Date shall be $78,431,000.

3. Proceeds of the Expected Term Issuance will be applied pursuant to the provisions of the Trust Indenture and the Junior Subordinated Warehouse Supplemental Indenture to the payment of the Principal Payment Amount.

4. For greater certainty, it is acknowledged that the Special Principal Payment Date will not be an Interest Payment Date under the Junior Subordinated Warehouse Supplemental Indenture and that accrued interest in respect of the principal amount of the Series 2017-1 Junior Subordinated Notes repaid on the Special Principal Payment Date will be paid on the next Payment Date.

5. Notwithstanding Section 3.4 of the Junior Subordinated Warehouse Supplemental Indenture, the Decrease Notice in respect of the Decrease occurring on the Special Principal Payment Date may be delivered no later than the second Business Day prior to the Special Principal Payment Date.

6. This Special Principal Payment Date Agreement applies only to the proceeds of the Expected Term Issuance and shall not be relied upon to complete any other repayment of principal of Series 2017-1 Junior Subordinated Notes. If the Special Principal Payment Date has not occurred by May 15, 2018 this Special Principal Payment Date Agreement shall cease to be of any force and effect.

7. Except as modified hereby, the provisions of the Junior Subordinated Warehouse Supplemental Indenture remain in full force and effect unamended.

8. Ontario Power Generation Inc. acknowledges and consents to the foregoing and directs the Indenture Trustee to enter into this Special Principal Payment Date Agreement.

*[Signature Page Follows]*

DATED this 20th day of April, 2018.

COMPUTERSHARE TRUST COMPANY OF CANADA, in its capacity as trustee of FAIR HYDRO TRUST, as Issuer by ONTARIO POWER GENERATION INC., not in its individual capacity but solely as Manager

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and Senior Vice President

By: _____
Name: John Lee
Title: Vice President - Treasurer

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Junior Subordinated Warehouse]*

**BNY TRUST COMPANY OF CANADA**, as Indenture Trustee

By: 

Name: Ahmad Adam
Title: Vice-President

*[Signature page to Special Principal Payment Date Agreement(2018-2) – Junior Subordinated Warehouse]*

ONTARIO POWER GENERATION INC.

By: _____
Name: Ken Hartwick
Title: Chief Financial Officer and
Senior Vice President

By: _____
Name: John Lee
Title: Vice President – Treasurer

*[Signature page to Special Principal Payment Date Agreement (2018-2) – Junior Subordinated Warehouse]*