

Nov. 14, 2014

OPG REPORTS Q3 NET INCOME ATTRIBUTABLE TO THE SHAREHOLDER OF \$118 MILLION BEFORE EXTRAORDINARY GAIN

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported net income attributable to the Shareholder before extraordinary gain for the three months ended Sept. 30, 2014 of \$118 million compared to \$30 million for the same quarter in 2013. The increased earnings were mainly a result of increased nuclear generation, lower operations, maintenance and administration (OM&A) expenses, and lower salary costs due to headcount reductions. As well, the increased earnings reflect spending restraints implemented over the past three years under the company's Business Transformation program.

Net income attributable to the Shareholder before extraordinary gain for the nine months ended Sept. 30, 2014 was \$475 million compared to \$131 million for the same period in 2013.

Tom Mitchell, OPG's President and CEO, said the improved financial results "illustrate the success of our determined and detailed business transformation.

"In addition to successfully ending the use of coal in our plants and operating a virtually emissions-free generation business, we have also lowered spending and achieved operational efficiencies by implementing improvements to our systems and processes. This has enabled OPG to reduce the number of employees from ongoing operations by about 2,000 to below 10,000. This was only accomplished with the dedicated efforts of all members of OPG staff."

Mr. Mitchell stressed that, "The positive financial results also include the impact of one-time events, including the extremely cold winter, and a gain in the value of the fund we have set aside to pay for the long-term storage of used nuclear fuel. OPG continues to generate electricity at a significantly lower price than the average of all other electricity generators."

Net income attributable to the Shareholder after extraordinary gain for the third quarter of 2014 was \$361 million compared to \$30 million for the same quarter in 2013. The increase primarily reflects the recognition of an extraordinary gain of \$243 million related to the forty-eight previously unregulated hydroelectric facilities prescribed for rate regulation effective July 1, 2014. The gain relates to deferred income taxes expected to be recovered from customers through future regulated prices in respect of these newly regulated facilities.

Net income attributable to the Shareholder after extraordinary gain for the nine months ended Sept. 30, 2014 was \$718 million compared to \$131 million for the same period in 2013. This increase was primarily due to the extraordinary gain recorded in the third quarter of 2014, and increased revenue from higher electricity spot market prices and trading revenue as a result of unseasonably cold weather during the first quarter in 2014. The improvement was also due to higher earnings from the Used Fuel Fund, an increase in nuclear generation, higher revenue from generating stations included in the Lower Mattagami River project, and lower salary costs due to headcount reductions.

Business Segment, Generating, and Operating Performance

Income before interest, income taxes, and extraordinary item from the electricity generation business segments was \$220 million in the third quarter of 2014, compared to \$77 million in the same quarter of 2013. The increase was primarily a result of increased nuclear generation and lower nuclear OM&A expenses due to fewer outage days.

Income before interest, income taxes, and extraordinary item from the electricity generation business segments was \$666 million for the nine months ended Sept. 30, 2014, compared to \$304 million for the same period of 2013. The increase was primarily due to higher hydroelectric generation revenue as a result of higher electricity spot market prices received for production from the 48 hydroelectric generating stations that have been prescribed for rate regulation which is effective July 1, 2014. The increase was also due to higher earnings from the Regulated – Nuclear Generation segment. The Contracted Generation Portfolio segment's earnings increased by \$101 million for the nine months ended Sept. 30, 2014 primarily due to higher revenue from the generating stations included in the Lower Mattagami River project.

The improved earnings for the Regulated – Nuclear Waste Management business segment of \$58 million for the first nine months of 2014 was primarily due to higher earnings on the Used Fuel Fund.

Total electricity generated during the three months ended Sept. 30, 2014 was 21.0 terawatt hours (TWh), compared to 20.1 TWh for the same quarter in 2013. This increase was mainly due to higher nuclear and regulated hydroelectric generation, partially offset by the impact of ending coal-fired generation. Total electricity generated during the nine months ended Sept. 30, 2014 was 61.3 TWh, compared to 61.4 TWh for the same period in 2013 as the impact of ending coal-fired generation was partially offset by higher nuclear generation and generation from the hydroelectric stations included in the Lower Mattagami River project.

For the three months ended Sept. 30, 2014, the capability factor at the Darlington Nuclear generating station (GS) was 98.4 per cent compared to 87.1 per cent for the same quarter in 2013. The increase was primarily due to a decrease in planned outage days. For the nine months ended Sept. 30, 2014, the capability factor increased to 90.7 per cent compared to 85.7 per cent for the same period in 2013 due to a decrease in unplanned outage days for the first nine months of the year. At the Pickering Nuclear GS, the capability factor improved to 79.9 per cent for the three months ended Sept. 30, 2014, compared to 75.7 per cent in the same quarter of 2013 due to a decrease in the number of planned outage days. The capability factor at the Pickering Nuclear GS of 74.7 per cent for the nine months ended Sept. 30, 2014 reflected a slight improvement from the 73.5 per cent for the same period in 2013.

The availability of OPG's hydroelectric generating stations in the Contracted Generation Portfolio segment for the nine month period ended Sept. 30, 2014 remained above 90 per cent, but decreased marginally due to unplanned outages.

Generation Development

OPG is undertaking a number of generation development and life extension projects to support Ontario's long-term electricity supply requirements and operate a generation portfolio that is essentially free of greenhouse gases and smog-causing emissions. Significant developments during the third quarter of 2014 are as follows:

Darlington Refurbishment

- The Darlington Refurbishment project is currently in the definition and site preparation phase. A detailed schedule and budget for the refurbishment of the four units is expected to be completed in 2015.
- The Retube and Feeder Replacement project is the largest work package of the Darlington Refurbishment project and represents a majority of the critical path schedule. On Sept. 30, 2014, a significant step towards completion of tooling delivery was made with the installation of the first retube platform at the mock-up facility at the Darlington Energy Complex. Prototype testing has commenced on the retube platform as part of the tooling scope.
- The remaining major project work packages including Turbines and Generators, Defueling and Fuel Handling, and Steam Generators are on schedule.

Lower Mattagami

- The Lower Mattagami River project is expected to be completed on schedule by June 2015 and within the approved budget of \$2.6 billion. The first 89 megawatt (MW) unit at the new Smoky Falls GS was declared in-service on Sept. 30, 2014, ahead of its original target completion date of Nov. 2014. The second 89 MW unit was declared in-service in Oct. 2014, ahead of the original target completion date of Jan. 2015 and the remaining unit at the Smoky Falls GS is expected to be declared in-service in Nov. 2014. The last incremental unit of the project, a 78 MW unit at the Kipling GS, is expected to be declared in-service ahead of the project's original target completion date of June 2015. As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, may acquire up to a 25 per cent interest in the assets placed in-service through its investment in the Lower Mattagami Limited Partnership (LMLP).

- During the first nine months of 2014, the Amisk-oo-Skow Finance Corporation made equity contributions to LMLP to acquire a 25 per cent interest in the value of the incremental units at the Little Long GS and Harmon GS. In Oct. 2014, the Amisk-oo-Skow Finance Corporation made equity contributions to acquire a 25 per cent interest in Unit 1 and Unit 2 of the new Smoky Falls GS. Life-to-date capital expenditures were \$2,282 million as of Sept. 30, 2014.

Atikokan Conversion

- In July 2014, construction to convert the Atikokan GS from coal to biomass fuel was completed ahead of its original target completion date of late Aug. 2014. The station was declared in-service as of July 24, 2014. While the total project cost is being finalized, the project's total cost is tracking to the budget of \$170 million. The converted station has a capacity of 205 MW and is subject to an energy supply agreement with the OPA. The Atikokan GS is the largest generating station in North America fuelled by 100 per cent biomass.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	2014	2013	2014	2013
Revenue	1,160	1,244	3,645	3,689
Fuel expense	161	186	464	541
Gross margin	999	1,058	3,181	3,148
Operations, maintenance and administration	595	684	1,931	2,027
Depreciation and amortization	184	243	546	727
Accretion on fixed asset removal and nuclear waste management liabilities	195	188	586	567
Nuclear Funds (earnings) – a reduction to expense	(161)	(165)	(538)	(462)
Income from investments subject to significant influence	(9)	(9)	(32)	(28)
Other net expenses	15	60	39	88
Income before interest, income taxes, and extraordinary item	180	57	649	229
Net interest expense	15	18	38	63
Income tax expense	46	9	133	35
Income before extraordinary item	119	30	478	131
Extraordinary item	243	-	243	-
Net income	362	30	721	131
Net income attributable to the Shareholder	361	30	718	131
Net Income attributable to non-controlling interest ¹	1	-	3	-
Income (loss) before interest, income taxes, and extraordinary item				
Electricity generation business segments	220	77	666	304
Regulated – Nuclear Waste Management	(32)	(22)	(42)	(100)
Services, Trading, and Other Non-Generation	(8)	2	25	25
Total income before interest, income taxes, and extraordinary item	180	57	649	229
Cash flow				
Cash flow provided by operating activities	360	391	993	983
Electricity generation (TWh)				
Regulated – Nuclear Generation	12.8	11.5	35.4	34.0
Regulated – Hydroelectric				
Existing regulated hydroelectric stations	5.1	4.9	14.6	14.1
Hydroelectric stations subject to rate regulation effective July 1, 2014	2.5	2.3	9.1	9.4
Contracted Generation Portfolio ²	0.6	1.4	2.2	3.9
Total electricity generation	21.0	20.1	61.3	61.4
Average sales prices and average revenue (¢/kWh)				
Average revenue for OPG ³	5.1	5.8	5.5	5.7
Average revenue for all electricity generators, excluding OPG ⁴	10.8	9.8	10.5	10.0
Nuclear unit capability factor (per cent)				
Darlington GS	98.4	87.1	90.7	85.7
Pickering GS	79.9	75.7	74.7	73.5
Availability (per cent)				
Regulated – Hydroelectric	90.7	90.2	91.4	91.8
Contracted Generation Portfolio – Hydroelectric	95.9	95.3	93.0	95.6
Equivalent forced outage rate				
Contracted Generation Portfolio – Thermal	2.1	5.7	2.9	8.7
Return on common equity for the 12 months ended Sep. 30, 2014 and Dec. 31, 2013 (%) ⁵			7.7	1.5
Return on common equity, excluding extraordinary gain, for the 12 months ended Sep. 30, 2014 and Dec. 31, 2013 (%) ⁵			5.1	1.5
Funds from operations interest coverage for the 12 months ended Sep. 30, 2014 and Dec. 31, 2013 (times) ⁵			2.5	2.8

¹ Relates to the 25 per cent interest of a corporation wholly owned by the Moose Cree First Nation in the incremental assets of the Lower Mattagami Limited Partnership.

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

³ Average revenue for OPG is comprised of regulated, market, energy supply agreement, and cost recovery agreement revenue. In 2014, average revenue for OPG excludes revenue from the cost recovery agreement for termination costs for the Nanticoke GS and Lambton GS and OPG's share of revenues and generation from PEC and Brighton Beach.

⁴ Revenues for other electricity generators are calculated as the sum of hourly Ontario demand multiplied by the hourly Ontario electricity price (HOEP), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

⁵ "Funds from operations interest coverage" and "Return on common equity" are non-GAAP financial measures and do not have any standardized meaning prescribed by US GAAP. Additional information about these measures is provided in OPG's Management's Discussion and Analysis for the period ended Sep. 30, 2014, under the heading, *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 focus is on the efficient production and sale of electricity from our generation assets, while operating in a safe, open and environmentally responsible manner.

Ontario Power Generation Inc.'s unaudited consolidated financial statements and Management's Discussion and Analysis as at and for the three and nine month periods ended Sept. 30, 2014, 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 more information, please contact:

Ontario Power Generation
Media Relations
416-592-4008 or 1-877-592-4008
Follow us @ontariopowergen

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ONTARIO POWER GENERATION INC.
MANAGEMENT'S DISCUSSION AND ANALYSIS
2014 THIRD QUARTER 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 unaudited interim consolidated financial statements and accompanying notes of Ontario Power Generation Inc. (OPG or Company) as at and for the three and nine month periods ended September 30, 2014. 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, related party transactions, 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, and MD&A as at and for the year ended December 31, 2013.

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. In the first quarter of 2014, the Ontario Securities Commission (OSC) 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 heading, *Exemptive Relief for Reporting under US GAAP*, under the section *Changes in Accounting Policies and Estimates*. This MD&A is dated November 12, 2014.

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 under the section *Risk Management*. 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 fuel costs and availability, generating station performance, cost of fixed asset removal and nuclear waste management, performance of investment funds, conversion of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit (OPEB) obligations, income taxes, electricity spot market prices, proposed new legislation, the ongoing evolution of the Ontario electricity industry, environmental and other regulatory requirements, health, safety and environmental developments, business continuity events, the weather, and the impact of regulatory decisions by the Ontario Energy Board (OEB). 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).

As at September 30, 2014, OPG's electricity generation portfolio had an in-service capacity of 16,958 megawatts (MW). OPG operates two nuclear generating stations, three thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. OPG also continues to preserve the option to convert two thermal generating stations to natural gas and/or biomass in the future. 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 (Brighton Beach) gas-fired combined cycle GS. 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 of the co-owned facilities is accounted for using the equity method of accounting, and OPG's share of income is presented in Income from investments subject to significant influence under the Contracted Generation Portfolio segment.

OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. (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.

OPG's Reporting Structure

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. These changes primarily reflect 48 of OPG's hydroelectric generating facilities being prescribed for rate regulation, effective July 1, 2014, and ending the use of coal at the Nanticoke and Lambton generating stations in 2013. OPG's reportable business segments, effective January 1, 2014, are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and other Non-Generation.

OPG's Regulated – Nuclear Generation and Regulated – Nuclear Waste Management segments are unchanged.

The Regulated – Hydroelectric segment continues to include the results of Sir Adam Beck 1, 2 and Pump GS, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Beginning in the first quarter of 2014, this segment also includes the results of 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014, under amended *Ontario Regulation 53/05*. The comparative information for the 48 hydroelectric stations, previously reported under the Unregulated – Hydroelectric segment in OPG's third quarter 2013 MD&A and financial statements, has been reclassified to conform to this new presentation.

The Contracted Generation Portfolio segment includes the results of operating generation facilities that are not prescribed for rate regulation. The segment primarily includes generating facilities that are under an Energy Supply Agreement (ESA) or other long-term contracts with the Ontario Power Authority (OPA).

Activities of generating stations that are not currently subject to a contract or rate regulation, but are available to generate electricity for sale, if required, are also included in the Contracted Generation Portfolio segment. Since the Lambton GS and Nanticoke GS were generating electricity up to the end of 2013, the activities related to these stations for the comparative period are reported in the Contracted Generation Portfolio segment. Effective January 1, 2014, the activities related to these stations are reported under the Services, Trading, and other Non-Generation business segment. These stations ended coal-fired operations as a result of a Shareholder declaration issued in March 2013 mandating that OPG end the use of coal at these stations by the end of 2013. OPG continues to preserve the option to convert these stations to natural gas and/or biomass in the future.

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. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are also included in this segment.

The Services, Trading, and other Non-Generation segment is a non-generation segment, and 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, sales of financial risk management products, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the United States (US) market. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of this segment. In addition, this segment includes revenue from real estate rentals and other unregulated service revenues. The above activities were previously reported in the Other segment.

Information for the comparative period has been adjusted to reflect the changes to OPG's reportable business segments and is labeled "adjusted".

The in-service generating capacity by business segment as of September 30, 2014 and December 31, 2013 was as follows:

	September 30 2014	As at December 31 2013 (adjusted)
(MW)		
Regulated – Nuclear Generation	6,606	6,606
Regulated – Hydroelectric ¹	6,426	6,432
Contracted Generation Portfolio ²	3,926	3,742
Total	16,958	16,780

¹ Includes the capacity of 48 of OPG's hydroelectric generating facilities which have been prescribed for rate regulation, effective July 1, 2014, per the amended *Ontario Regulation 53/05*.

² Includes the capacity of two units at the Thunder Bay GS, until the conversion of one unit to use advanced biomass fuel has been completed. The balance also 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, 2014, the in-service capacity of the Contracted Generation Portfolio segment increased by 184 MW. The increase was a result of an 89 MW unit at the new Smoky Falls GS being declared in-service in September 2014, a 78 MW unit at the Harmon GS being declared in-service in June 2014, and a 69 MW unit at the Little Long GS being declared in-service in January 2014. These increases were partially offset by the removal of the existing 52 MW Smoky Falls station from service in July 2014 in preparation for the station's planned decommissioning. In addition, the in-service capacity of the Regulated – Hydroelectric segment decreased by 6 MW as a result of a reduction in the capacity of the units at the Aguasabon GS from 51 MW to 45 MW in May 2014.

HIGHLIGHTS

Overview of Results

This section provides an overview of OPG's unaudited interim consolidated operating results. A detailed discussion of OPG's performance by reportable segment is included under the section, *Discussion of Operating Results by Business Segment*.

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	2014	2013	2014	2013
Revenue	1,160	1,244	3,645	3,689
Fuel expense	161	186	464	541
Gross margin	999	1,058	3,181	3,148
Operations, maintenance and administration	595	684	1,931	2,027
Depreciation and amortization	184	243	546	727
Accretion on fixed asset removal and nuclear waste management liabilities	195	188	586	567
Earnings on nuclear fixed asset removal and nuclear waste management funds	(161)	(165)	(538)	(462)
Property and capital taxes	12	14	22	43
Income from investments subject to significant influence	(9)	(9)	(32)	(28)
Restructuring	3	46	15	48
	819	1,001	2,530	2,922
Income before other loss (income), interest, income taxes, and extraordinary item	180	57	651	226
Other loss (income)	-	-	2	(3)
Income before interest, income taxes, and extraordinary item	180	57	649	229
Net interest expense	15	18	38	63
Income before income taxes and extraordinary item	165	39	611	166
Income tax expense	46	9	133	35
Income before extraordinary item	119	30	478	131
Extraordinary item	243	-	243	-
Net income	362	30	721	131
Net income attributable to the Shareholder	361	30	718	131
Net income attributable to non-controlling interest ¹	1	-	3	-
Electricity production (TWh) ²	21.0	20.1	61.3	61.4
Cash flow				
Cash flow provided by operating activities	360	391	993	983

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 incremental assets of the Lower Mattagami Limited Partnership (LMLP).

² Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach. Electricity production for the comparative period has been adjusted to include 50 percent of the production from PEC and Brighton Beach.

Third Quarter

Net income attributable to the Shareholder increased by \$331 million during the third quarter of 2014, compared to the same quarter in 2013. Income before interest, income taxes, and extraordinary item increased by \$123 million. The following summarizes the significant items which caused the variance:

Significant factors that increased income before interest, income taxes, and extraordinary item:

- Higher gross margin of \$67 million for the Regulated – Nuclear Generation segment as a result of higher electricity generation of 1.3 terawatt hours (TWh)
- Lower nuclear operations, maintenance and administration (OM&A) expenses primarily due to lower planned outage costs, lower overtime costs, and unfilled staff vacancies
- Lower restructuring expense of \$43 million due to the recognition of severance costs in 2013 related to the Lambton, Nanticoke, and Thunder Bay stations
- Lower salary costs of \$15 million due to business efficiencies reflected in lower staff numbers.

Significant factors that reduced income before interest, income taxes, and extraordinary item:

- Lower contract revenue of \$31 million from the Thunder Bay reliability must run contract, which expired at the end of 2013. The contract was approved by the OEB in July 2013 and contract revenue was recognized in the third quarter of 2013 related to the period from January 1, 2013 to September 30, 2013
- Lower revenue of \$25 million during the third quarter of 2014 as a result of lower electricity spot market prices received for generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014. Until the OEB issues its decision on OPG's current application for regulated prices, these stations continue to receive revenue based on Ontario electricity spot market prices.

Income tax expense increased by \$37 million during the third quarter of 2014, compared to the same quarter in 2013. The increase was primarily due to the increase in income during the quarter.

Forty-eight of OPG's previously unregulated hydroelectric facilities were prescribed for rate regulation effective July 1, 2014. During the third quarter of 2014, OPG recognized additional regulatory assets related to deferred income taxes expected to be recovered from customers through future regulated prices in respect of these newly regulated facilities, resulting in an extraordinary gain of \$243 million in the consolidated statements of income.

Year-To-Date

Net income attributable to the Shareholder was \$718 million and increased by \$587 million during the first nine months of 2014, compared to the same period in 2013. Income before interest, income taxes, and extraordinary item increased by \$420 million. The following summarizes the significant items which caused the variance:

Significant factors that increased income before interest, income taxes, and extraordinary item:

- Increase in revenue of approximately \$210 million primarily as a result of higher electricity spot market prices and trading revenue, the majority of which occurred during the first quarter of 2014 as a result of the unseasonably cold winter
- Higher earnings on the Used Fuel Segregated Fund (Used Fuel Fund) of \$77 million primarily due to higher returns as a result of a higher Ontario consumer price index (CPI) and favourable market conditions. This increase was net of the impact of the Bruce Lease Net Revenues Variance Account
- Increase in gross margin of \$76 million for the Regulated – Nuclear Generation segment due to higher electricity generation
- Higher revenue from the incremental units at the Little Long GS and Harmon GS which were declared in service in 2014
- Lower salary costs of \$43 million due to lower staff numbers

- Lower restructuring expense of \$33 million as a result of the recognition of severance costs of \$48 million in 2013.

Significant factors that reduced income before interest, income taxes, and extraordinary item:

- Lower revenue from the Thunder Bay GS of \$20 million due to lower contract revenue from the reliability must run contract which expired at the end of 2013, partially offset by generation revenue received at Ontario electricity spot market prices in 2014.

Net interest expense decreased by \$25 million for the nine months ended September 30, 2014, compared to the same period in 2013. The decrease was primarily due to amounts capitalized under construction in progress for the Darlington Refurbishment project.

Income tax expense increased by \$98 million for the first nine months of 2014 compared to the same period in 2013. The increase reflects the increase in income during 2014.

Segment Results

The following table summarizes OPG's income before interest, income taxes, and extraordinary item by business segment:

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 (adjusted)	2014	2013 (adjusted)
<i>(millions of dollars)</i>				
<i>Income (loss) before interest, income taxes, and extraordinary item</i>				
Regulated – Nuclear Generation	143	22	132	20
Regulated – Hydroelectric	63	82	472	323
Contracted Generation Portfolio	14	(27)	62	(39)
Total electricity generation business segments	220	77	666	304
Regulated – Nuclear Waste Management	(32)	(22)	(42)	(100)
Services, Trading, and other Non-Generation	(8)	2	25	25
	180	57	649	229

Income before interest, income taxes, and extraordinary item from the electricity generation business segments increased by \$143 million during the third quarter of 2014, compared to the same quarter in 2013. The increase was primarily a result of higher earnings from the Regulated – Nuclear Generation segment due to an increase in generation volume and a reduction in OM&A expenses. In addition, earnings from the Contracted Generation Portfolio segment were higher during the third quarter of 2014 primarily due to lower restructuring expense. These increases in earnings were partially offset by lower earnings from the Regulated – Hydroelectric segment during the third quarter primarily as a result of lower electricity spot market prices received for generation produced by 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014. Until the OEB issues its decision on OPG's current application for regulated prices, these stations continue to receive revenue based on Ontario electricity spot market prices.

Income before interest, income taxes, and extraordinary item from the electricity generation business segments increased by \$362 million for the nine months ended September 30, 2014, compared to the same period in 2013. The increase was partly due to higher generation revenue from the Regulated – Hydroelectric segment as a result of higher electricity spot market prices received for the generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014. The increase in earnings from the electricity generation business segments was also due to higher earnings from the Regulated – Nuclear Generation and

Contracted Generation Portfolio segments. The higher earnings from the Regulated – Nuclear Generation segment were primarily due to higher generation volume.

The Contracted Generation Portfolio segment's income before interest, income taxes, and extraordinary item increased by \$101 million for the nine months ended September 30, 2014 primarily due to higher revenue from the generating stations included in the Lower Mattagami River project. The increase reflected revenue for generation from the incremental units at the Little Long GS and Harmon GS, which received revenue determined under the hydroelectric ESA after they were declared in-service in 2014. The higher revenue was also a result of higher generation volume and higher electricity spot market prices from the existing assets of the Lower Mattagami River project. The existing assets are not subject to the revenue mechanism under the hydroelectric ESA until the last incremental unit of the Lower Mattagami River project is declared in-service. Until that time, the generation from these stations receives the electricity spot market price.

The improvement in earnings for the Regulated – Nuclear Waste Management business segment of \$58 million for the nine months ended September 30, 2014 was primarily a result of higher earnings on the Used Fuel Fund. The improvement in earnings was partially offset by higher accretion expense which reflects the increase in asset retirement obligations due to the passage of time.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2014 and 2013 was as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(TWh)	2014	2013 (adjusted)	2014	2013 (adjusted)
Regulated – Nuclear Generation	12.8	11.5	35.4	34.0
Regulated – Hydroelectric				
Existing regulated hydroelectric generating stations	5.1	4.9	14.6	14.1
Hydroelectric generating stations prescribed for rate regulation effective July 1, 2014	2.5	2.3	9.1	9.4
Contracted Generation Portfolio ¹	0.6	1.4	2.2	3.9
Total OPG electricity generation	21.0	20.1	61.3	61.4
Total electricity generation by all other generators in Ontario	17.2	18.5	53.7	54.0

¹ Includes OPG's share of generation volume from its 50 percent ownership interests in PEC and Brighton Beach.

During the third quarter of 2014, electricity generation from the Regulated – Nuclear Generation segment increased by 1.3 TWh, compared to the same quarter in 2013, primarily as a result of fewer planned and unplanned outage days at the Darlington Nuclear GS.

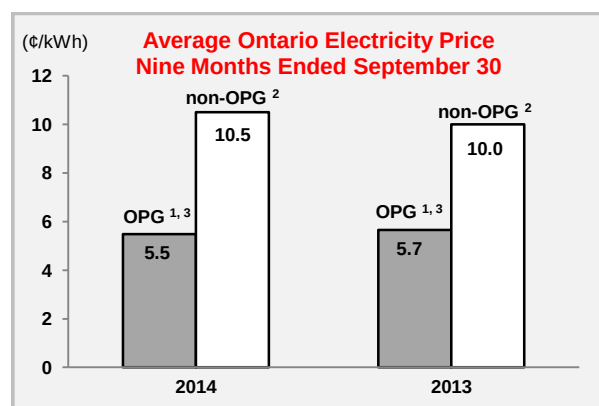
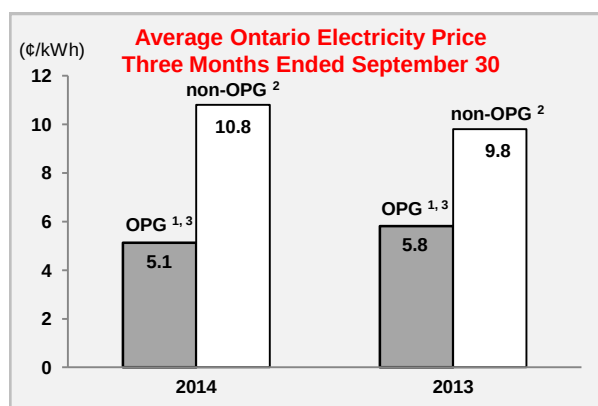
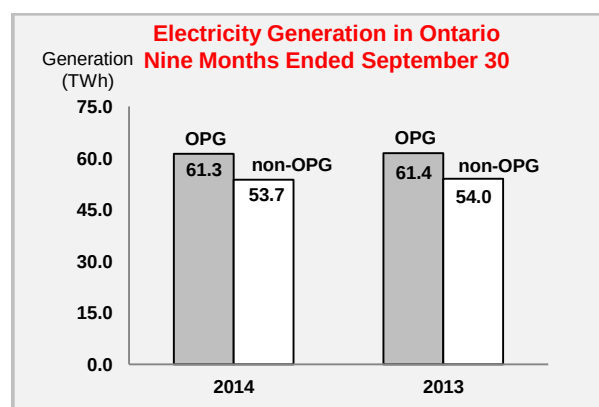
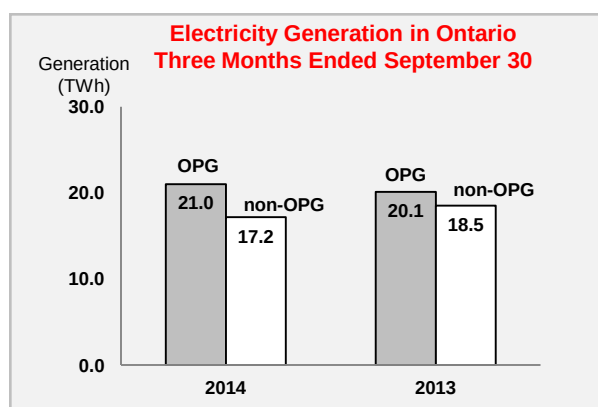
The increase in electricity generation of 0.2 TWh for the existing regulated hydroelectric generating stations during the third quarter of 2014 is primarily a result of higher flows on the Niagara and St. Lawrence Rivers. Higher flows on river systems in eastern Ontario during the third quarter of 2014 contributed to the increase in electricity generation of 0.2 TWh from the hydroelectric stations prescribed for rate regulation effective July 1, 2014.

The decrease in electricity generation from the Contracted Generation Portfolio segment during the third quarter of 2014, compared to the same quarter of 2013, was primarily due to lower generation associated with the Nanticoke GS and the Lambton GS of 1.0 TWh as a result of ending coal-fired operations at these stations in 2013.

For the nine months ended September 30, 2014, the decrease in generation of 0.1 TWh was mainly due to lower generation of 1.7 TWh from the Contracted Generation Portfolio segment. This decrease was partially offset by higher nuclear generation of 1.4 TWh and higher generation from the existing regulated hydroelectric generating stations.

Lower generation from the Contracted Generation Portfolio segment during the nine months ended September 30, 2014 was primarily due to the decrease in generation of 2.7 TWh as a result of ending coal-fired operations at the Lambton GS and the Nanticoke GS in 2013. This decrease was partially offset by higher generation of 0.6 TWh from the stations included in the Lower Mattagami River project.

Fewer outage days at the Darlington Nuclear GS during the nine months ended September 30, 2014, compared to the same period in 2013, contributed to the increase in nuclear generation. Higher flows on the Niagara and St. Lawrence Rivers contributed to the increase in electricity generation of 0.5 TWh from the existing regulated hydroelectric stations during the nine months ended September 30, 2014, compared to the same period in 2013.



¹ Average revenue for OPG is comprised of regulated revenues, market based revenues, revenues from ESAs, and other energy revenue from cost recovery agreements. In 2014, average revenue for OPG excludes the revenue from the cost recovery agreement for termination costs for the Nanticoke GS and Lambton GS as these stations ended coal-fired operations in 2013. Average revenue for OPG also excludes OPG's share of revenues and generation from PEC and Brighton Beach.

² Revenues for other electricity generators are calculated as the sum of hourly Ontario demand multiplied by the weighted average hourly Ontario electricity price (HOEP), plus total global adjustment payments, plus the sum of hourly net exports multiplied by the HOEP, less OPG's generation revenue.

³ Regulated revenues included in the average revenue for OPG are based on cost of service regulated prices declared interim, effective January 1, 2014. When the order establishing new regulated prices is issued, OPG expects to recover the difference between the approved new regulated prices and the current prices, for the period between January 1, 2014 and the date when the order is issued.

Average Sales Prices and Average Revenue

OPG's average revenue reflects the average sales prices for all of its electricity generation segments. 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 nuclear facilities operated by OPG and existing regulated hydroelectric generating stations are discussed in OPG's annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

The average sales price for the Regulated – Nuclear Generation segment during the three and nine month periods ended September 30, 2014 was 5.5 ¢/kWh compared to 5.7 ¢/kWh during the same periods in 2013. The decrease was primarily due to a lower rate rider during 2014 related to the recovery of approved variance and deferral account balances.

The average sales price for the Regulated – Hydroelectric segment during the third quarter of 2014 was 3.3 ¢/kWh compared to 3.7 ¢/kWh during the same quarter in 2013. The decrease was primarily due to lower prices received for the 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014. Prior to the OEB establishing regulated rates for these stations, the generation from these stations will continue to receive the Ontario electricity spot market price. The average sales price for these stations during the third quarter of 2014 was 2.1 ¢/kWh compared to 3.1 ¢/kWh during the same quarter in 2013. The decrease was primarily due to a lower HOEP during the quarter as a result of lower Ontario primary demand and higher hydroelectric and nuclear baseload generation, offset slightly by higher natural gas prices.

During the nine months ended September 30, 2014, the average sales price for the Regulated – Hydroelectric segment was 4.1 ¢/kWh compared to 3.5 ¢/kWh during the same period in 2013. The increase in average sales price was primarily due to higher sales prices related to the stations which have been prescribed for rate regulation, effective July 1, 2014. The increase in the average sales price for these stations was primarily due to the unseasonably cold temperatures during the first quarter of 2014, compared to the same quarter in 2013. The colder temperature resulted in higher natural gas prices and higher Ontario primary demand.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended September 30, 2014 was \$360 million, compared to \$391 million for the same quarter in 2013. This decrease in cash was primarily due to lower cash receipts as a result of lower revenue from cost recovery contracts and lower rate riders. In addition, there were higher cash payments for pension contributions which were partially offset by lower OM&A expenditures.

Cash flow provided by operating activities for the nine months ended September 30, 2014 was \$993 million, compared to \$983 million for the same period in 2013. This increase in cash was primarily due higher trading revenues and lower OM&A expenditures. The increase was partially offset by lower cash receipts from revenue from cost recovery contracts.

Funds from Operations Interest Coverage

Funds from Operations (FFO) Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage is measured over a 12-month period. FFO Interest Coverage for the twelve months ended September 30, 2014 was 2.5 times and 2.8 times for December 31, 2013. The FFO Interest Coverage decreased primarily due to an increase in interest costs, which was partially offset by higher cash flows provided by operating activities. The increase in interest costs was primarily due to higher pension and OPEB discount rates and an increase in pension and OPEB benefit obligations.

Return on Common Equity

Return on Common Equity (ROE) is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to maintain value for the Shareholder. ROE is measured over a 12-month period. ROE for the twelve months ended September 30, 2014 was 7.7 percent and 1.5 percent for December 31, 2013. ROE increased for the period primarily due to higher net income attributable to the Shareholder and an extraordinary gain of \$243 million recognized in the third quarter of 2014 related to the 48 hydroelectric facilities prescribed for rate regulation effective July 1, 2014. The ROE calculated using net attributable income to the Shareholder, excluding extraordinary gain, over the twelve months ended September 30, 2014 was 5.1 percent.

FFO Interest Coverage and ROE are not measurements in accordance with US GAAP and should not be considered as alternative measures to net income, cash flows from operating activities, or any other measure of performance under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of performance and are consistent with its corporate strategy to operate on a financially sustainable basis. The definition and calculation of FFO Interest Coverage and ROE can be found under the section, *Supplementary Non-GAAP Financial Measures*.

Recent Developments

New Generating Assets In-Service

Since the end of the second quarter in 2014, the following assets were declared in-service:

- *Lower Mattagami:* The first 89 MW unit at the new Smoky Falls GS was declared in-service on September 30, 2014, ahead of its original target completion date of November 2014. The second 89 MW unit was declared in-service in October 2014, ahead of the original target completion date of January 2015 and the remaining unit at the Smoky Falls GS is expected to be declared in-service in November 2014.
- *Atikokan Biomass Conversion:* In August 2014, OPG obtained final approval from the OPA and has declared the Atikokan GS in Commercial Operation, effective as of July 24, 2014. The converted station has a capacity of 205 MW and is the largest generating station in North America fuelled by 100 percent biomass.

OPG's major generation development projects are discussed under the heading, *Project Excellence*.

CORE BUSINESS AND STRATEGY

OPG's mandate is to reliably and cost-effectively produce electricity from its diversified portfolio of generating assets, while operating in a safe, open, and environmentally responsible manner. OPG's mission is to be Ontario's low cost electricity generator through a focus on three corporate strategies:

- Operational Excellence
- Project Excellence
- Financial Sustainability.

The following sections provide an update to OPG's disclosures related to operational excellence, project excellence, and financial sustainability. A detailed discussion of OPG's three corporate strategies is included in the 2013 annual MD&A under the headings, *Operational Excellence*, *Project Excellence*, and *Financial Sustainability*.

Operational Excellence

Operational excellence at OPG's nuclear, hydroelectric, and thermal generating facilities is accomplished by generating safe, reliable, and cost-effective electricity.

Nuclear Generating Assets

In August 2014, the Canadian Nuclear Safety Commission (CNSC) presented its Staff Integrated Safety Assessment of Canadian Nuclear Power Plants for 2013. Darlington Nuclear GS achieved the highest possible safety and control rating, its fifth consecutive excellent performance evaluation. Pickering Nuclear GS also received positive safety and control ratings from the CNSC staff, with improved performance recognized in the areas of radiation protection and security.

The Joint Review Panel (JRP) process related to the Deep Geologic Repository (DGR) project for the long-term management of low and intermediate level waste (L&ILW) continued during 2014. For further details on the L&ILW DGR project, refer to the heading, *Project Excellence*.

During the third quarter of 2014, Unit 7 of the Pickering Nuclear GS commenced a planned maintenance outage. In addition, planning activities for the Vacuum Building Outage scheduled to be executed at the Darlington Nuclear GS in 2015 continued.

In December 2013, OPG submitted a licence renewal application for the Darlington Nuclear GS that would span the refurbishment period. The hearing dates for the licence renewal application have not been scheduled but are expected to take place in August and November 2015. The existing licence for the station expires on December 31, 2015.

Generation and reliability performance at the Pickering and Darlington Nuclear generating stations during the third quarter of 2014 are discussed under the heading, *Regulated – Nuclear Generation Segment* in the section *Discussion of Operating Results by Business Segment*.

Hydroelectric Generating Assets

OPG's hydroelectric generating stations that are currently prescribed for rate regulation and the stations which have been prescribed for rate regulation effective July 1, 2014 are included in the Regulated – Hydroelectric segment. Hydroelectric generating stations that are not subject to rate regulation by the OEB are included in the Contracted Generation Portfolio segment. A description of these reportable business segments is included under the heading, *OPG's Reporting Structure*.

In consideration of current and future market conditions and the related revenue mechanisms, OPG continues to evaluate and implement plans to increase capacity, maintain performance, and extend the operating life of its hydroelectric generating assets. During the third quarter of 2014, OPG completed major equipment overhauls and rehabilitation work on Unit 11 of the R.H. Saunders GS and a transformer bank replacement at the Pine Portage GS. Rehabilitation work on Unit 3 of the Sir Adam Beck Pump GS and Unit 1 of the Lower Notch GS continues. Other hydroelectric generation projects are discussed under the heading, *Project Excellence*.

Thermal Generating Assets

OPG's operating thermal generating stations are included in the Contracted Generation Portfolio segment. These stations operate as peaking facilities, depending on electricity demand. In April 2014, OPG ended all coal-fired operations as all existing coal inventory was utilized in the last coal-fired unit at the Thunder Bay GS.

Thermal assets that are no longer available to generate electricity are included in the Services, Trading, and other Non-Generation segment once the assets are removed from service. With the end of coal-fired generation at the Nanticoke GS and the Lambton GS in 2013, OPG continues to preserve the option to convert these stations to natural gas and/or biomass in the future. The activities required to preserve this option are reflected in the Services, Trading, and other Non-Generation segment in 2014. OPG is seeking recovery of ongoing costs to preserve the option to convert the units. If recovery is not allowed, OPG will consider all options regarding the future of these stations, including full closure and decommissioning.

Discussion regarding the conversion of the Atikokan GS is included under the heading, *Project Excellence*.

Environmental Performance

During the first nine months of 2014, there were no significant changes to environmental legislation affecting the Company. There was a reduction in environmental risk as the Company's largest coal-fired stations, the Lambton and Nanticoke generating stations, ended coal-fired operations by the end of 2013. In addition, OPG ended all coal-fired operations in April 2014 as all existing coal inventory was utilized in the last coal-fired unit at the Thunder Bay GS. As a result of these closures, carbon dioxide and acid gas emissions decreased by 91 percent during the first nine months of 2014, compared to the same period in 2013.

Disclosures relating to environmental policies and procedures, and environmental risks are provided in the 2013 annual MD&A.

Project Excellence

OPG is pursuing several generation development projects. OPG's major projects include the Darlington Refurbishment, new hydroelectric generation and plant expansions, and the conversion of coal-fired generating units to alternative fuels. The status of OPG's major projects as of September 30, 2014 are outlined below.

Project <i>(millions of dollars)</i>	Capital expenditures		Approved budget	Planned in-service date	Status
	Year-to-date	Life-to-date			
Darlington Refurbishment	539	1,332			This project is part of Ontario's Long-Term Energy Plan. A detailed schedule and budget for the refurbishment of the four units is expected to be completed in 2015. See update below.
Lower Mattagami	300	2,282	2,600	June 2015	Project is on budget and ahead of schedule. See update below.
Deep Geologic Repository for Low and Intermediate Level Waste ¹	8 ¹	175 ¹			See update below.
Atikokan Biomass Conversion	24	168	170	August 2014	Construction completed ahead of schedule and on budget.

¹ Expenditures are funded by the nuclear fixed asset removal and nuclear waste management liabilities.

Darlington Refurbishment

The Darlington Refurbishment project is a multi-phase program comprised of individual projects of various scales and sizes. In particular, the project consists of the following five major project work packages:

- Retube and Feeder Replacement
- Turbines and Generators
- Defueling and Fuel Handling
- Steam Generators
- Balance of Plant.

The Darlington Refurbishment project is currently in the definition phase. Refurbishment of the four Darlington units is currently estimated to cost less than the \$10 billion high confidence estimate in 2013 dollars, excluding capitalized interest and escalation. A detailed schedule and budget for the refurbishment of the four units is expected to be completed in 2015.

There are 18 pre-requisite projects currently underway at Darlington that are to be completed in advance of the execution phase of the Darlington Refurbishment project. OPG has implemented a collaborative front-end planning process that integrates OPG's engineering oversight with each vendor's engineering studio. This has resulted in significant improvements in the quality and timeliness of engineering deliverables.

The Heavy Water Storage and Drum Handling Facility, one of Darlington's 18 pre-requisite projects, is required to store heavy water from the Darlington units during refurbishment. Construction challenges have resulted in schedule delays and cost growth in this portion of the project as a result of difficulties in completing work which includes temporary construction barriers, temporary bracing, anchors, and dewatering equipment. OPG is implementing a

revised plan to mitigate the construction complexities and schedule risks, including contingency plans to avoid potential impacts on the Darlington Refurbishment project schedule.

The Retube and Feeder Replacement project is the largest work package of the Darlington Refurbishment project and represents a majority of the critical path schedule. A significant part of this project is the development of tooling prototypes and systems to simulate inspection tasks and precise sequencing of work prior to commencing work on the reactor. On September 30, 2014, a significant step towards completion of tooling delivery was made with the installation of the first retube platform at the mock-up facility located at the Darlington Energy Complex. Prototype testing has commenced on the retube platform.

The remaining major project work packages, including Turbines and Generators, Defueling and Fuel Handling, and Steam Generators are on schedule. All preliminary engineering is complete for the Turbines and Generators project. Defueling detailed design is nearing completion on the Defueling and Fuel Handling project. Detailed engineering is progressing on track to meet detailed design completion on the Steam Generators project. Contracts for Balance of Plant projects are in the process of being issued in order to complete detailed design.

OPG submitted the Integrated Implementation Plan (IIP) to the CNSC in December 2013, for which the CNSC provided feedback in April 2014. OPG is working on the closure of gaps identified in the IIP and has requested CNSC staff acceptance by the end of 2014.

Deep Geologic Repository for L&ILW

The public hearing days for the environmental assessment (EA) and the site preparation and construction licence of the L&ILW DGR concluded in September 2014. Further comprehensive evidence has been provided to the JRP and closing remarks were submitted by intervenors and OPG. A decision from the federal Minister of Environment on the EA is expected in 2015. A decision on the site preparation and construction licence from the JRP is also expected in 2015. During this process, OPG continues to engage and communicate with local communities, including ongoing consultation with the Saugeen Ojibway Nation.

Lower Mattagami River project

The first 89 MW unit at the new Smoky Falls GS was declared in-service on September 30, 2014, ahead of its original target completion date of November 2014. The second 89 MW unit was declared in-service on October 9, 2014, ahead of the original target completion date of January 2015. The remaining unit is expected to be declared in-service in November 2014. These new units replaced the existing 52 MW Smoky Falls station, which was removed from service in July 2014 in preparation for the station's planned decommissioning.

The last incremental unit of the project, a 78 MW unit at the Kipling GS, is expected to be declared in-service ahead of the original target completion date for the Lower Mattagami River project of June 2015.

As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, may acquire up to a 25 percent interest in the assets through its investment in the LMLP. During the first nine months of 2014, the Amisk-oo-Skow Finance Corporation made equity contributions of \$53 million to LMLP to acquire a 25 percent interest in the value of the incremental units at the Little Long GS and Harmon GS. In October 2014, the Amisk-oo-Skow Finance Corporation made equity contributions to acquire a 25 percent interest in Unit 1 and Unit 2 of the new Smoky Falls GS.

Atikokan Conversion

In July 2014, construction to convert the Atikokan GS from coal to biomass fuel was completed, ahead of its original target completion date of late August 2014. In August 2014, the OPA approved the documentation that OPG submitted on the converted station and OPG declared the Atikokan GS in Commercial Operation, effective as of July 24, 2014. While the total project cost is being finalized, the project's total cost is tracking to the approved budget of \$170 million. The converted station has a capacity of 205 MW and is subject to an ESA with the OPA, which was

executed in 2012. The Atikokan GS is the largest generating station in North America fuelled by 100 percent biomass.

Financial Sustainability

As a commercial enterprise, OPG's financial priority is to achieve a consistent level of financial performance that will ensure its long-term financial sustainability and maintain the value of its assets for its Shareholder – the Province of Ontario. Inherent in this priority are three objectives:

- enhance profitability by increasing revenue
- improve efficiency and reduce costs
- ensure a strong financial position that enhances OPG's ability to finance its operations and generation development projects.

Revenue Growth

OPG's revenue strategy focuses on revenue growth, while taking into account the impact on Ontario electricity ratepayers by setting challenging business planning targets. OPG currently has multiple sources of revenue, including:

- regulated revenue from nuclear and most baseload hydroelectric generating facilities
- contract revenue from ESAs and cost recovery agreements for most of its remaining unregulated facilities
- unregulated revenue based on electricity spot market prices for certain facilities that are not prescribed a regulated price or not subject to revenue from an ESA
- non-generation revenues.

Effective July 1, 2014, an amendment to *Ontario Regulation 53/05* requires OPG's 48 previously unregulated hydroelectric stations that are not under an ESA to be prescribed for rate regulation.

OPG's objectives in all applications for regulated prices are to clearly demonstrate that costs for its regulated operations are prudently incurred and should be fully recovered, and to earn an appropriate return on its regulated assets.

In September 2013, OPG filed an application with the OEB for new regulated prices effective January 1, 2014. In the second quarter of 2014, as part of common regulatory practice, OPG filed an update to the requested regulatory prices, including rate riders, to reflect material changes from forecast information provided in its application. OPG's update requested that the nuclear generation regulated price, excluding rate riders, decrease from the previous request of \$69.91/MWh to \$67.60/MWh and the regulated price, excluding rate riders, for the generation from the existing regulated hydroelectric facilities increase from the previous request of \$42.31/MWh to \$42.75/MWh. For the 48 newly regulated stations, effective July 1, 2014, OPG decreased the requested hydroelectric generation regulated price, excluding rate riders, from the previous request of \$47.59/MWh to \$47.57/MWh. In addition, the requested rate riders were updated to \$1.35/MWh for the output from the nuclear facilities and \$3.36/MWh for the output from the existing regulated hydroelectric facilities, based on the final December 31, 2013 variance and deferral account balances and updated production forecasts. These prices would allow OPG to recover its costs for these stations while earning an appropriate return on these assets. The oral hearing and final arguments were completed during the third quarter of 2014. The OEB's decision is expected in the fourth quarter of 2014. OPG is also planning a future rate application to request recovery of variance and deferral account balances as at December 31, 2014.

OPG has negotiated ESAs and cost recovery agreements for some of its unregulated hydroelectric assets and its thermal assets. In the second quarter of 2014, OPG and the OPA executed the Thunder Bay Biomass ESA with respect to the conversion of the Thunder Bay GS to advanced biomass fuel. OPG continues to negotiate ESAs for new development and conversion projects.

During the first nine months of 2014, a portion of OPG's electricity production from certain unregulated facilities was sold at the Ontario electricity spot market price. This includes production from stations that are prescribed for rate regulation effective July 1, 2014. OPG's financial results benefited from the increase in Ontario electricity spot market prices during the nine months ended September 30, 2014 primarily due to unseasonably cold temperatures in Ontario during January and February 2014.

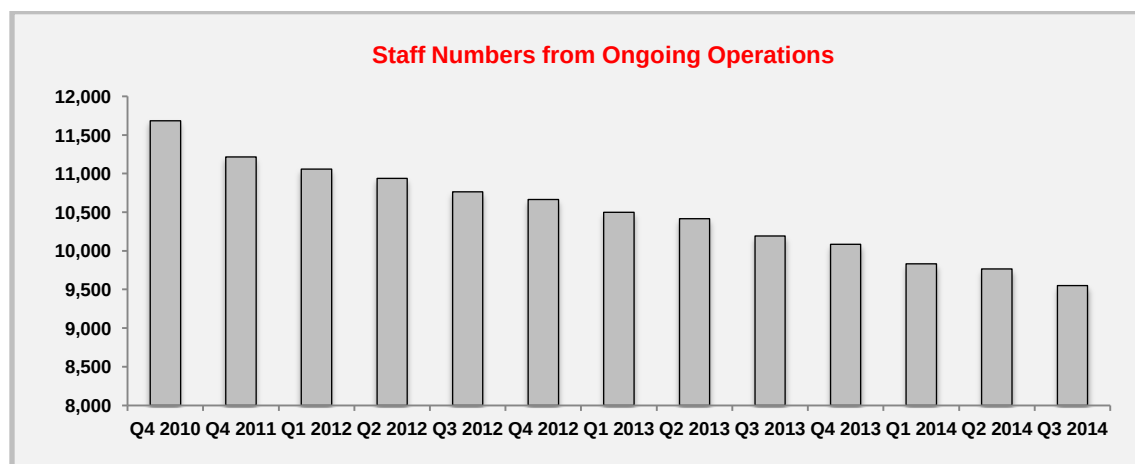
OPG also earns non-electricity generation revenues through a number of sources, including: isotope and heavy water sales; the lease of the Bruce A and B nuclear stations; joint ventures associated with PEC and Brighton Beach; trading and other non-hedging activities; real estate rentals and sales; and the provision of technical and engineering services to third parties. During the first nine months of 2014, OPG's trading revenue significantly increased from higher prices realized on interconnected market sales to neighbouring energy markets.

To increase non-generation revenues, OPG, through its wholly owned subsidiary, Canadian Nuclear Partners Inc., continues to explore opportunities to provide management and technical services to other utilities and power sector organizations.

Improving Efficiency and Reducing Costs

OPG is aggressively pursuing efficiency and productivity improvements while reducing costs. To accomplish this, OPG launched a multi-year Business Transformation initiative in 2011 to create a streamlined company with a sustainable cost structure. OPG has implemented a centre-led organizational model to more efficiently utilize its resources. Each business unit has launched initiatives to improve efficiencies and reduce work through process streamlining. These initiatives are driving sustainable change, while ensuring that there is no adverse impact on the safety, reliability, and environmental sustainability of OPG's operations.

OPG plans to use attrition to reduce its year-end 2016 staff numbers from ongoing operations by over 2,300 employees from the 2011 level. This reduction is expected to result in lower labour costs compared to the 2011 level. During the January 1, 2011 to September 30, 2014 period, OPG's staff numbers from ongoing operations has been reduced by over 2,000, primarily through attrition. The reduction in staff numbers has already saved OPG approximately \$475 million over the period from January 1, 2011 to September 30, 2014.



Strengthening Financial Position

In addition to its initiatives to increase revenue, achieve efficiencies, and reduce costs, OPG also employs the following four strategies to strengthen its financial position:

- **Ensure sufficient liquidity:** OPG's primary sources of liquidity and capital include funds generated from operations, bank financing, credit facilities provided by the Ontario Electricity Financial Corporation (OEF),

and capital market financing. During the first nine months of 2014, cash flow provided by operating activities increased by \$10 million, compared to the same period in 2013. In the second quarter of 2014, OPG renewed and extended its \$1 billion bank credit facility to May 2019. OPG also has access to a \$500 million general corporate credit facility with the OEFC which will expire on December 31, 2014. OPG intends to continue to access the capital markets, where appropriate, to obtain cost effective financing for generation development projects.

- **Maintain an investment grade credit rating:** OPG's current investment grade credit ratings have enabled it to secure financing at cost effective interest rates. In the third quarter of 2014, Standard & Poor's reaffirmed OPG's long-term credit rating at A- with a negative outlook. In the first quarter of 2014, DBRS Ltd. re-affirmed the long-term credit rating on OPG's debt at A (low) and the commercial paper rating at R-1 (low). All ratings from DBRS Ltd. have a stable outlook.
- **Ensure that generation development projects are economic and provide for cost recovery and an appropriate return:** During the third quarter of 2014, OPG continued to negotiate ESAs for new development and conversion projects. Updates on these projects for the third quarter of 2014 are discussed under the heading *Project Excellence* in the section, *Core Business and Strategy*.
- **Evaluate financial performance:** OPG continuously evaluates its financial performance using key credit rating and financial metrics, including ROE, and FFO Interest Coverage. For further details, refer to the ROE and FFO Interest Coverage disclosure in the section, *Supplementary Non-GAAP Financial Measures*.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

Key performance indicators that directly pertain to OPG's mandate and corporate strategies are measures of production efficiency, cost-effectiveness, environmental, and safety performance. OPG evaluates the performance of its generating stations using a number of key performance indicators. The measures used vary depending on the generation technology.

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. After ending coal-fired operations at the Nanticoke GS and the Lambton GS, OPG no longer uses the Thermal Start Guarantee Rate and the Thermal OM&A Expense per MW as indicators of performance. In addition, OPG previously reported Nuclear Production Unit Energy Cost and hydroelectric Equivalent Forced Outage Rate (EFOR). Effective January 1, 2014, OPG has moved to Nuclear Total Generating Cost (TGC) per MWh as a cost performance indicator for its nuclear generating facilities and reports Hydroelectric Availability as the only measure of the reliability of its hydroelectric generating facilities. OPG continues to report the Nuclear Unit Capability Factor as a measure of its nuclear station performance, and Hydroelectric OM&A expense per MWh as a measure of the cost effectiveness of its hydroelectric generating facilities.

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 the total of fully-allocated OM&A expenses from ongoing nuclear operations, including total pension and OPEB costs, nuclear fuel expense including expenses related to used fuel storage and disposal, and capital project costs for ongoing nuclear operations, divided by net nuclear electricity generation.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	2014	2013	2014	2013
Regulated generation sales	703	659	1,947	1,941
Variance accounts	77	23	(87)	31
Other	7	67	318	209
Total revenue	787	749	2,178	2,181
Fuel expense	81	79	230	224
Variance and deferral accounts	(16)	(17)	(49)	(43)
Total fuel expense	65	62	181	181
Gross margin	722	687	1,997	2,000
Operations, maintenance and administration	444	500	1,457	1,490
Depreciation and amortization	128	159	387	470
Property and capital taxes	7	6	21	21
Income before other income, interest, income taxes, and extraordinary item	143	22	132	19
Other income	-	-	-	(1)
Income before interest, income taxes, and extraordinary item	143	22	132	20

The increase in segment earnings of \$121 million during the third quarter of 2014, compared to the same quarter in 2013, was primarily a result of an increase in generation and a reduction in OM&A expenses. Higher electricity generation of 1.3 TWh increased gross margin by \$67 million during the third quarter of 2014. The increase in generation was primarily due to fewer outage days at the Darlington and Pickering nuclear generating stations. OM&A expenses decreased by \$56 million during the third quarter of 2014 compared to the same period in 2013. The decrease in expenditures due to lower planned outage costs, lower overtime costs, and unfilled staff vacancies was the primary reason for the reduction of OM&A expenses during the three months ended September 30, 2014.

Higher segment earnings of \$112 million during the nine months ended September 30, 2014, compared to the same period in 2013, was also primarily due to an increase in generation of 1.4 TWh and lower OM&A expenses during the third quarter of 2014. OM&A expenses decreased primarily as a result of lower staff numbers and fewer outage days, offset by an increase in maintenance activities.

A lower rate rider for nuclear generation in 2014 decreased gross margin by \$29 million during the third quarter of 2014 and \$77 million during the nine months ended September 30, 2014, compared to the same periods in 2013. The impact of the lower rate rider was largely offset by a corresponding decrease in amortization expense related to regulatory balances.

The changes in other revenue for the three and nine month periods ended September 30, 2014, compared to the same periods in 2013, was primarily due to the change in the fair value of the derivative liability embedded in the terms of the Bruce Power lease agreement (Bruce Lease). The changes in the fair value of this derivative are recorded in other revenue, with a corresponding change in the regulatory asset related to the Bruce Lease Net Revenues Variance Account. As such, there was no income impact related to the change in the fair value of the derivative liability.

The Unit Capability Factors for the Darlington and Pickering Nuclear generating stations and the Nuclear TGC per MWh were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Unit Capability Factor (%)				
Darlington GS	98.4	87.1	90.7	85.7
Pickering GS	79.9	75.7	74.7	73.5
Nuclear TGC per MWh (\$/MWh)	42.83	51.35	48.70	52.12

The higher Unit Capability Factor at the Darlington Nuclear GS for the three months ended September 30, 2014, compared to the same period in 2013, was primarily due to lower planned and unplanned outage days. The increase in Unit Capability Factor at the Pickering Nuclear GS was primarily due to a decrease in the number of planned outage days.

The higher Unit Capability Factor at the Darlington Nuclear GS for the nine months ended September 30, 2014, was primarily due to a decrease in both planned and unplanned outage days compared to the same period in 2013.

The decrease in Nuclear TGC per MWh during the three and nine month periods ending September 30, 2014, compared to the same period in 2013, was primarily due to lower OM&A expenses and increased production.

Regulated – Nuclear Waste Management Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	2014	2013	2014	2013
Revenue	31	31	89	84
Operations, maintenance and administration	32	33	94	90
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	192	185	575	556
Earnings on nuclear fixed asset removal and nuclear waste management funds	(161)	(165)	(538)	(462)
Loss before interest, income taxes, and extraordinary item	(32)	(22)	(42)	(100)

Lower earnings from the Nuclear Funds contributed to a higher loss for the segment for the three months ended September 30, 2014, compared to the same period in 2013. The decrease in Nuclear Fund earnings was primarily due to less favourable market conditions on the Used Fuel Fund earnings. The higher Ontario CPI during the third quarter of 2014 partially offset the impact of the less favourable market conditions. Higher accretion expense also contributed to the increased segment loss during the third quarter of 2014.

Higher earnings on the Used Fuel Fund contributed to the segment's improved results for the nine month period ended September 30, 2014, compared to the same period in 2013. An increase in the Ontario CPI and favourable market conditions contributed to the higher Used Fuel Fund earnings during the first nine months of 2014. The increased earnings in the segment during this period were partially offset by higher accretion expense.

Regulated – Hydroelectric Segment

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 ¹ (adjusted)	2014	2013 ¹ (adjusted)
<i>(millions of dollars)</i>				
Regulated generation sales	196	194	569	557
Spot market sales	53	71	401	267
Variance accounts	6	6	15	38
Other	20	23	102	69
Total revenue	275	294	1,087	931
Fuel expense	89	87	239	237
Variance accounts	2	2	10	12
Total fuel expense	91	89	249	249
Gross margin	184	205	838	682
Operations, maintenance and administration	80	77	241	218
Depreciation and amortization	40	45	122	137
Property and capital taxes	1	1	1	2
Income before other loss, interest, income taxes, and extraordinary item	63	82	474	325
Other loss	-	-	2	2
Income before interest, income taxes, and extraordinary item	63	82	472	323

¹ The comparative amounts have been adjusted to include the activities of 48 of OPG's hydroelectric generating facilities that have been prescribed for rate regulation, effective July 1, 2014, per the amended *Ontario Regulation 53/05*.

During the third quarter of 2014, lower revenue from spot market sales resulted in the decrease in the segment's income before interest, income taxes, and extraordinary item, compared to the same quarter in 2013. The decrease in revenue is a result of lower electricity spot market prices received during the third quarter of 2014 for 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014.

The significant increase in income before interest, income taxes, and extraordinary item during the nine months ended September 30, 2014, compared to the same period in 2013, was primarily due to higher gross margin. The increase in gross margin was largely the result of significantly higher electricity spot market prices received during the first quarter of 2014 for the generation produced by the 48 hydroelectric generating stations that have been prescribed for rate regulation effective July 1, 2014. Higher ancillary services and other station revenue during the period also contributed to the higher gross margin for the segment. The higher gross margin during the nine months ended September 30, 2014 was partially offset by higher OM&A expenses primarily due to an increase in overhaul expenditures incurred for Unit 3 at the Sir Adam Beck Pump GS.

The impact of the lower rate rider during the three and nine month periods ended September 30, 2014, compared to the same period in 2013, was largely offset by a corresponding decrease in amortization expense related to regulatory balances.

The Regulated – Hydroelectric availability and OM&A expense per MWh were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 (adjusted)	2014	2013 (adjusted)
Hydroelectric Availability (%)	90.7	90.2	91.4	91.8
Hydroelectric OM&A expense per MWh (\$/MWh)	10.5	10.7	9.9	9.3

The hydroelectric availability during the third quarter of 2014 increased slightly as a result of lower unplanned outages compared to the availability for the same period in 2013. The hydroelectric availability during the nine months ended

September 30, 2014 was lower than the availability during the same period in 2013 due to a higher number of planned and unplanned outage days at larger hydroelectric units in 2014.

The increase in hydroelectric OM&A expense per MWh for the nine months ended September 30, 2014, compared to the same period in 2013, was primarily due to higher OM&A expenses.

Contracted Generation Portfolio Segment

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 (adjusted)	2014	2013 (adjusted)
<i>(millions of dollars)</i>				
Revenue	67	190	224	524
Fuel expense	5	35	32	111
Gross margin	62	155	192	413
Operations, maintenance and administration	43	103	129	307
Depreciation and amortization	11	35	22	106
Accretion on fixed asset removal liabilities	1	3	5	10
Property and capital taxes	1	4	(2)	11
Income from investments subject to significant influence	(9)	(9)	(32)	(28)
Restructuring	1	46	8	48
Income (loss) before other income, interest, income taxes, and extraordinary item	14	(27)	62	(41)
Other income	-	-	-	(2)
Income (loss) before interest, income taxes, and extraordinary item	14	(27)	62	(39)

For the 2013 three and nine month comparative periods, the Contracted Generation Portfolio segment includes the operating results of the Nanticoke GS and Lambton GS, including revenue and expenses from generation and from the Contingency Support Agreement with the OEFC. Given these stations ended coal-fired generation at the end of 2013, the activities of these stations, including expenses incurred in 2014 associated with placing the stations in reserve status, are being reported in the Services, Trading, and other Non-Generation segment effective January 1, 2014. The end of coal-fired operations and the change in presentation for the segment results in overall lower revenue, partially offset by lower OM&A and depreciation and amortization expenses for the three and nine month periods ended September 30, 2014, compared to the same periods in 2013. The improvement in the segment's results for the three and nine month periods ended September 30, 2014, were also partially offset by the stations' 2013 net losses due to the costs to preserve the option to convert the stations to natural gas and/or biomass in the future. OPG is seeking recovery of these ongoing costs to preserve the units. If recovery is not allowed, OPG will consider all options regarding the future of these stations, including full closure and decommissioning.

The increase in segment income of \$41 million during the third quarter in 2014, compared to the same quarter in 2013, was primarily due to the recognition of severance costs of \$46 million in 2013 related to the Lambton GS, Nanticoke GS, and Thunder Bay GS. The improvement in earnings was also due to an increase in revenue for production from the incremental units at the Little Long GS and Harmon GS, which were declared in-service in January 2014 and June 2014, respectively, and which received revenue determined under the hydroelectric ESA. Segment earnings were unfavourably affected during the third quarter of 2014, compared to the same quarter in 2013, as a result of lower contract revenue from the Thunder Bay reliability must run contract, which expired at the end of 2013. The Thunder Bay reliability must run contract was approved by the OEB in July 2013 and the contract revenue of \$31 million recognized in the third quarter of 2013 was related to the period from January 1, 2013 to September 30, 2013.

For the nine months ended September 30, 2014, segment income increased by \$101 million, compared to the same period in 2013. The increase was partly due to the recognition of severance costs of \$48 million in 2013, compared

to \$8 million in 2014. Segment earnings were also higher during the nine months ended September 30, 2014, compared to the same period in 2013, due to revenue from the incremental units at the Little Long GS and Harmon GS. In addition, higher generation volume from the existing assets included in the Lower Mattagami River project and higher electricity spot market prices for the electricity generation from those assets in the first quarter also contributed to the increase in segment income during the nine month period.

The hydroelectric availability, hydroelectric OM&A expense per MWh, and the thermal EFOR for the segment were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 (adjusted)	2014	2013 (adjusted)
Hydroelectric Availability (%)	95.9	95.3	93.0	95.6
Hydroelectric OM&A expense per MWh (\$/MWh)	24.0	30.0	24.0	38.9
Thermal EFOR (%)	2.1	5.7	2.9	8.7

The hydroelectric availability during the third quarter of 2014 remained consistent with the availability during the same quarter in 2013. The hydroelectric availability during the nine months ended September 30, 2014 was lower by 2.6 percent compared to the availability during the same period in 2013, primarily due to higher unplanned outage days.

The decrease in hydroelectric OM&A expense per MWh for the three and nine month periods ended September 30, 2014, compared to the same periods in 2013, was primarily due to the impact of higher generation volume from the hydroelectric stations included in this segment.

The decrease in thermal EFOR for the three and nine month periods ended September 30, 2014, compared to the same periods in 2013, was primarily a result of ending coal-fired operations at the Nanticoke GS and the Lambton GS in 2013.

Services, Trading, and other Non-Generation Segment

	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013 (adjusted)	2014	2013 (adjusted)
(millions of dollars)				
Revenue	30	10	153	50
Fuel expense	-	-	2	-
Gross margin	30	10	151	50
Operations, maintenance and administration	26	1	96	3
Depreciation and amortization	5	4	15	14
Accretion on fixed asset removal liabilities	2	-	6	1
Property and capital taxes	3	3	2	9
Restructuring	2	-	7	-
(Loss) income before other income, interest, income taxes, and extraordinary item	(8)	2	25	23
Other income	-	-	-	(2)
(Loss) income before interest, income taxes, and extraordinary item	(8)	2	25	25

The inclusion of the results of the Nanticoke GS and the Lambton GS in this segment, as discussed under the section, *The Company*, resulted in higher revenue, OM&A expenses, and restructuring expenses for both the three and nine month periods ended September 30, 2014, compared to the same periods in 2013. The increase in OM&A expenses was largely offset by revenue for termination costs as provided for under the Contingency Support

Agreement with the OEFC for these stations. The agreement's early termination provision allows OPG to recover actual costs incurred that cannot be reasonably avoided or mitigated during 2014.

The decrease in earnings of \$10 million during the third quarter of 2014, compared to the same quarter in 2013, was partly due to the recognition of restructuring costs and OM&A expenses to preserve the option to convert the Nanticoke GS and Lambton GS to natural gas and/or biomass in the future. OPG is seeking recovery of these ongoing costs to preserve the units. If recovery is not allowed, OPG will consider all options regarding the future of these stations, including full closure and decommissioning.

For the nine months ended September 30, 2014, the segment's income remained unchanged at \$25 million, compared to the same period in 2013. Higher interconnected market sales from the unseasonably cold winter during the first quarter of 2014 resulted in higher trading margin for electricity sold to neighbouring energy markets. This increase in earnings was largely offset by higher pension and OPEB expenses and OM&A expenses related to costs to preserve the Nanticoke and Lambton GS.

Income Taxes

Income tax expense for the three months ended September 30, 2014 was \$46 million compared to income tax expense of \$9 million for the same quarter in 2013. The increase in income tax expense was primarily due an increase in income before taxes.

Income tax expense for the nine months ended September 30, 2014 was \$133 million compared to \$35 million for the same period in 2013. The increase in income tax expense was primarily due to an increase in income before taxes.

LIQUIDITY AND CAPITAL RESOURCES

OPG's primary sources of liquidity and capital include funds generated from operations, bank financing, credit facilities provided by the OEFC, and capital market financing. These sources are used for multiple purposes including: to invest in plants and technologies; to fund obligations such as contributions to the pension fund and the Used Fuel Fund and the Decommissioning Segregated Fund (together the Nuclear Funds); and to service and repay long-term debt.

Changes in cash and cash equivalents were as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	2014	2013	2014	2013
Cash and cash equivalents, beginning of period	625	699	562	413
Cash flow provided by operating activities	360	391	993	983
Cash flow used in investing activities	(347)	(379)	(1,082)	(1,168)
Cash flow (used in) provided by financing activities	(1)	40	164	523
Net increase	12	52	75	338
Cash and cash equivalents, end of period	637	751	637	751

For a discussion regarding cash flow provided by operating activities and FFO Interest Coverage, refer to the discussion under the *Highlights* section.

Investing Activities

Cash flow used in investing activities during the third quarter of 2014 decreased by \$32 million compared to the same quarter in 2013. This decrease was primarily due to lower capital expenditures for the Lower Mattagami River project

and the Atikokan Biomass Conversion project. This was partially offset by higher expenditures for the Darlington Refurbishment project.

Cash flow used in investing activities during the nine months ended September 30, 2014 decreased by \$86 million compared to the same period in 2013. The decrease was primarily due to lower capital expenditures for:

- the Lower Mattagami River project as a result of two incremental units being declared in-service during the first nine months of 2014
- the Niagara Tunnel project, which was declared in-service in March 2013
- the Atikokan Biomass Conversion project
- partially offset by higher expenditures for the Darlington Refurbishment project.

OPG's forecast capital expenditures for 2014 are approximately \$1.6 billion, which includes amounts for hydroelectric development and nuclear refurbishment in addition to sustaining capital investments.

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 2014, OPG renewed and extended both tranches to May 2019. As at September 30, 2014, there were no outstanding borrowings under the bank credit facility.

As at September 30, 2014, OPG maintained \$25 million of short-term, uncommitted overdraft facilities, and \$374 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, 2014, a total of \$335 million of Letters of Credit had been issued. This included \$302 million for the supplementary pension plans, \$32 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. In the third quarter of 2014, the maximum amount of co-ownership interest that can be sold under this agreement was reduced to \$150 million and the expiry date was extended from November 30, 2014 to November 30, 2016. As at September 30, 2014, of the \$302 million of Letters of Credit issued for the supplementary pension plans, \$80 million were issued under this agreement.

OPG also maintains a Niagara Tunnel project credit facility with the OEFC for an amount up to \$1.6 billion. As at September 30, 2014, advances under this facility were \$1,065 million, with no new borrowing during the third quarter of 2014. OPG's borrowing under this facility is limited to the cost of the project. This credit facility expires on December 31, 2014.

The Lower Mattagami Energy Limited Partnership (LME) maintains a \$600 million bank credit facility to support the funding requirements of the Lower Mattagami River project. The facility consists of two \$300 million multi-year term tranches. In the third quarter of 2014, OPG extended the maturity of the first tranche to August 2019, from August 2018. The second tranche matures in August 2015. As at September 30, 2014, there was no commercial paper outstanding under this program. Subsequently, in October 2014, \$100 million of commercial paper was issued. In June 2014, LME issued senior notes totalling \$200 million with a maturity date of 2024. The effective interest rate for these notes was 3.5 percent and the coupon interest rate was 3.4 percent.

As at September 30, 2014, OPG's long-term debt outstanding was \$5,781 million, including \$553 million due within one year. OPG entered into an agreement with the OEFC in December 2013 for a \$500 million general corporate credit facility. As at September 30, 2014, there were no outstanding borrowings under this credit facility. This credit facility expires on December 31, 2014.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's unaudited interim consolidated financial position using selected balance sheet data:

<i>(millions of dollars)</i>	As At	
	September 30 2014	December 31 2013
Property, plant and equipment - net	17,370	16,738
The increase was primarily due to an increase in construction in progress for the refurbishment of the Darlington Nuclear GS and the Lower Mattagami River project. This was partially offset by depreciation expense for the nine months ended September 30, 2014.		
Nuclear fixed asset removal and nuclear waste management funds <i>(current and non-current portions)</i>	14,183	13,496
The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Fund, partially offset by reimbursements of expenditures on nuclear fixed asset removal and nuclear waste management.		
Fixed asset removal and nuclear waste management liabilities	16,846	16,257
The increase was primarily a result of accretion expense due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		
Regulatory assets <i>(current and non-current portions)</i>	5,964	5,400
The increase was primarily due to the recognition of regulatory assets related to deferred income taxes and unamortized amounts recorded in accumulated other comprehensive income (AOCI) related to pension and OPEB obligations pertaining to facilities prescribed for rate regulation effective July 1, 2014, as well as additions to the Pension OPEB Cost Variance Account		
Long-term accounts payable and accrued charges	525	653
The decrease was primarily due to a decrease of \$91 million in the fair value of the derivative liability embedded in the Bruce Lease. The decrease in the fair value of the derivative liability was offset by the Bruce Lease Net Revenues Variance Account. The decrease is also due to settlement of various legal claims during the nine months ended September 30, 2014		

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 that OPG undertakes include guarantees, which provide financial or performance assurance to third-parties on behalf of certain subsidiaries, and long-term fixed price 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, 2013. A discussion of changes in accounting policies is included in OPG's interim consolidated financial statements for the third quarter of 2014 under the heading, *Changes in Accounting Policies and Estimates*. Disclosure regarding OPG's critical accounting policies is included in OPG's 2013 annual MD&A.

Exemptive Relief for Reporting under US GAAP

During the first quarter of 2014, OPG received 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 without becoming a Securities and Exchange Commission registrant, or issuing public debt. The exemption 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 International Financial Reporting Standards (IFRS) specific to entities with rate-regulated activities.

This exemption replaces the exemptive relief received by OPG from the OSC in December 2011. The 2011 exemption allowed OPG to file consolidated financial statements based on US GAAP for financial years that began on or after January 1, 2012, but before January 1, 2015.

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's plan to convert to IFRS, effective January 1, 2012, was discontinued. Prior to the adoption of US GAAP as the basis for OPG's financial reporting, the Company had planned to adopt IFRS effective January 1, 2012. OPG had substantively completed its IFRS conversion project, which included separate diagnostic, development, and implementation phases, when it suspended the project and began the evaluation of converting to US GAAP in the fourth quarter of 2011. If a future transition to IFRS is required, conversion work can effectively be restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project.

Regulatory Assets Related to Newly Regulated Hydroelectric Facilities

Forty-eight of OPG's previously unregulated hydroelectric facilities were prescribed for rate regulation effective July 1, 2014. As a result, OPG recognized additional regulatory assets related to deferred income taxes and unamortized amounts recorded in AOCI in respect of pension and OPEB obligations during the third quarter of 2014. The recognition of the increase in regulatory assets related to deferred income taxes resulted in an extraordinary gain of \$243 million in the consolidated statements of income. The additional regulatory assets related to pension and OPEB obligations resulted in an increase of \$184 million in other comprehensive income, net of \$61 million in income taxes.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance under US GAAP. The core principle of ASU 2014-09 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. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgement and estimates may be required compared to the requirements under existing US GAAP. The standard will be effective for OPG's 2017 fiscal year, including interim periods in 2017. In applying the standard, entities would have the option between two retrospective transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption and includes additional disclosures. OPG is currently assessing the impact of this new standard on its consolidated financial statements and has not yet determined the method by which it will adopt the standard in 2017.

RISK MANAGEMENT

This risk management disclosure should be read in conjunction with the *Risk Management* section included in OPG's 2013 annual MD&A which provides a detailed discussion of OPG's governance structure, inherent risks, and activities associated with identifying and managing risks. The following discussion provides an update of OPG's risk management activities.

Operational Risks

Risks Associated with Existing Generating Operations

OPG is exposed to variable output from its existing generating stations that could adversely impact its financial performance.

Deep Geologic Repository for L&ILW

OPG is developing plans for a DGR to address the need for the long-term management of L&ILW. The opposition to deep geologic disposal of L&ILW may impede the ability of OPG to develop disposal plans acceptable to major stakeholders. The JRP is conducting an examination of the environmental effects of the L&ILW DGR project and public hearings concluded in September 2014. There is a risk of further delays to the EA approval and/or the issuance of the site preparation and construction license caused by additional regulatory, political, legal, and other requirements.

Risks Associated with Major Development Projects

The risks associated with the cost, schedule, and technical aspects of the major development projects could adversely impact OPG's financial performance and its corporate reputation.

Darlington Refurbishment

The Darlington generating units are currently forecasted to reach their end of lives between 2019 and 2020, based on original design assumptions. The refurbishment of the Darlington Nuclear GS is expected to extend its operating life by approximately 30 years. In the recent mandate letter for the Minister of Energy, the Government of Ontario confirmed its commitment to refurbish the nuclear units at the Darlington Nuclear GS, noting expectations that the project will be completed efficiently and effectively. A high degree of critical scrutiny will continue for the pre-requisite

projects supporting the Darlington Refurbishment project. OPG also continues to work with its Shareholder to determine an appropriate cost recovery mechanism in connection with the project, while considering the impact to ratepayers.

A large proportion of the costs of the Darlington Refurbishment will be paid to contractors and suppliers, including vendors that will engineer, procure, and construct components of the project. There are financial and credibility risk exposures for OPG if actual costs significantly exceed the estimates. The early introduction of corrective actions is expected to reduce this risk. OPG also continues to undertake activities to manage the availability of skilled resources and project management staff over the life of the project.

Financial Risks

Commodity Markets

Changes in the market price of electricity or of the 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.

OPG's revenue from its unregulated assets is also affected by changes in the market or spot price of electricity. The majority of this exposure should be eliminated with the implementation of a regulated price for 48 of OPG's previously unregulated hydroelectric facilities, which were prescribed for rate regulation in accordance with amended *Ontario Regulation 53/05*, effective July 1, 2014.

The percentages hedged of OPG's expected generation, fuel requirements, and emission 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.

	2014 ¹	2015	2016
Estimated generation output hedged ²	89%	98%	100%
Estimated fuel requirements hedged ³	81%	74%	69%
Estimated nitric oxide emission requirement hedged ⁴	100%	100%	100%
Estimated sulphur dioxide emission requirement hedged ⁴	100%	100%	100%

¹ Includes forecast for the remainder of the year.

² Represents the portion of megawatt-hours of expected future generation production which is subject to regulated prices established by the OEB, OEFC, and OPA, or other electricity contracts which are used as hedges.

³ Represents the approximate portion of megawatt-hours of expected generation production and year-end inventory targets from each type of facility (nuclear and thermal) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios.

⁴ Represents the approximate portion of megawatt-hours of expected thermal production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under *Ontario Regulation 397/01*.

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be affected by movements in the US dollar relative to the Canadian dollar, and by prevailing interest rates on its borrowings and investment programs.

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 are primarily denominated in US dollars. In addition, the market price of electricity in Ontario is influenced by the exchange rate as a result of the interaction between the Ontario and neighbouring US interconnected electricity markets. The Ontario electricity spot market is also influenced by US dollar denominated commodity prices for natural gas which is used in electricity generation. 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 September 30, 2014, OPG had forward contracts outstanding to purchase US \$12 million.

The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to refinance existing debt and/or undertake new financing. The management of these risks is undertaken by 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 new financing. As at September 30, 2014, OPG did not have any interest rate swap contracts outstanding.

Trading

OPG's financial performance can be affected by its trading activities.

OPG's trading operations are closely monitored and total exposures are measured and reported to senior management on a daily basis. One of the metrics used to measure the financial risk of this trading activity is Value at Risk (VaR). For the third quarter of 2014, the utilization of VaR averaged \$0.4 million, compared to an average of \$0.5 million for the third quarter of 2013.

Credit

Deterioration in counterparty credit and non-performance by suppliers can adversely impact OPG's earnings and cash flow from operations.

OPG manages its exposure to various suppliers or counterparties by evaluating their financial condition and ensuring that appropriate collateral, or other forms of security, are held by OPG. OPG's credit exposure relating to energy markets transactions as at September 30, 2014 was \$369 million, including \$351 million to the Independent Electricity System Operator. Over 95 percent of the remaining \$18 million exposure is related to investment grade counterparties.

Nuclear Waste and Decommissioning Obligations and Nuclear Funds

The cost estimates of nuclear waste obligations are based on assumptions that evolve over time and could impact OPG's contributions to the Nuclear Funds to cover these costs.

The cost estimates of OPG's nuclear waste management and decommissioning obligations are based on numerous underlying assumptions that are inherently uncertain. These assumptions include station end of life dates, waste volumes, waste packaging systems, and waste disposal systems. To address the inherent uncertainty, OPG undertakes a review to validate the underlying assumptions and baseline cost estimates at least once every five years. Any changes to the underlying assumptions and updated lifecycle costs estimates will be developed and submitted for review and approval in 2016 as part of the next Reference Plan update.

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

During the most recent interim period, there have been no changes in the Company's policies and procedures and other processes that comprise its internal controls over financial reporting, that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

QUARTERLY FINANCIAL HIGHLIGHTS

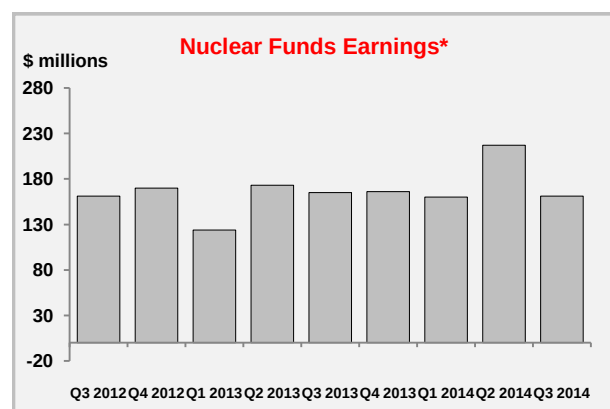
The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters. This financial information has been prepared in accordance with US GAAP.

<i>(millions of dollars – except where noted) (unaudited)</i>	September 30 2014	June 30 2014	March 31 2014	December 31 2013
Revenue	1,160	1,098	1,387	1,174
Income before extraordinary item	119	115	242	4
Net income attributable to the Shareholder	361	115	242	4
Income before extraordinary item per common share	\$0.46	\$0.45	\$0.94	\$0.02
Net income per common share (dollars)	\$1.41	\$0.45	\$0.94	\$0.02

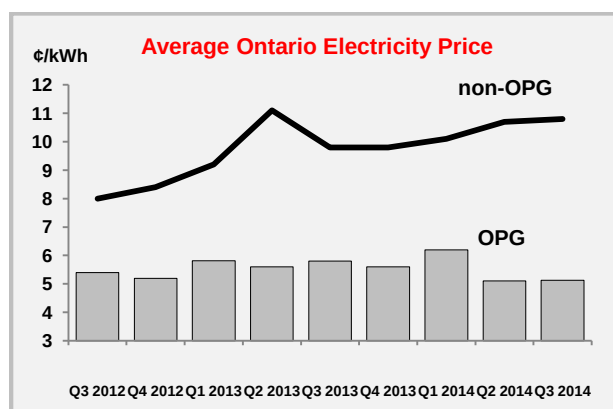
<i>(millions of dollars – except where noted) (unaudited)</i>	September 30 2013	June 30 2013	March 31 2013	December 31 2012
Revenue	1,244	1,190	1,255	1,195
Income before extraordinary item	30	73	28	31
Net income attributable to the Shareholder	30	73	28	31
Income before extraordinary item per common share	\$0.12	\$0.28	\$0.11	\$0.12
Net income per common share (dollars)	\$0.12	\$0.28	\$0.11	\$0.12

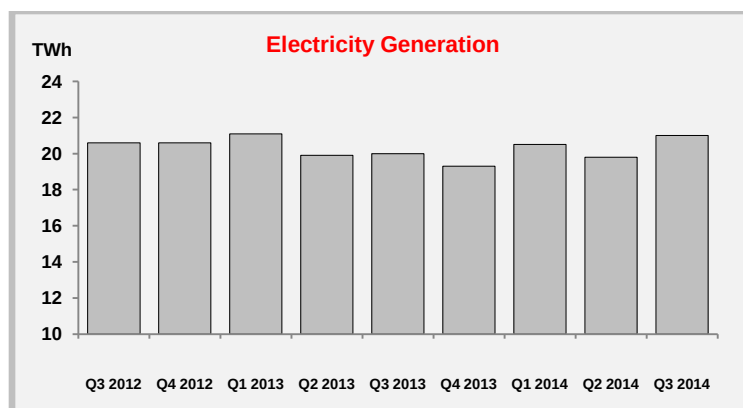
Trends

OPG's quarterly results are affected by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are 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. In addition to average revenue and generation volume, OPG's income is affected by earnings from the Nuclear Funds.



*net of regulatory variance account





Items which affected net income during 2014 are described below.

- During the first quarter of 2014, increase in revenue of \$132 million primarily as a result of higher electricity spot market prices and trading revenue
- During the second quarter of 2014, higher earnings from the Used Fuel Fund of \$41 million primarily due to the impact of higher Ontario CPI and favourable market conditions
- During the second quarter of 2014, higher generation volume from the stations included in the Lower Mattagami River project
- During the second quarter of 2014, higher expenditures of \$53 million in the regulated generation segments primarily related to outage activities.

Additional items which affected net income prior to 2014 are described in OPG's 2013 annual MD&A.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with US GAAP, certain non-GAAP financial measures are also presented in OPG's MD&A and unaudited interim consolidated financial statements. 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, interim consolidated financial statements and the notes thereto 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 a measure consistent with the corporate strategy to operate on a financially sustainable basis. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with US GAAP, but as an indicator of operating performance.

The definitions of the non-GAAP financial measures are as follows:

(1) **ROE** is defined as net income attributable to the Shareholder divided by average equity attributable to the Shareholder excluding AOCl, for the period. ROE is measured over a 12-month period. The definition of ROE was refined as of January 1, 2014 as a result of the non-controlling interest established, which reflects equity contributions made by the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation to the LMLP in the first quarter of 2014.

(2) **FFO 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 includes net interest expense plus interest income, interest capitalized to fixed and intangible assets, interest related to regulatory assets and liabilities, and interest on pension and OPEB projected benefit obligations less expected return on pension plan assets for the period.

FFO Interest Coverage is measured over a period of twelve months and is calculated as follows:

	For the twelve months ended	
	September 30	December 31
(millions of dollars – except where noted)	2014	2013
FFO before interest		
Cash flow provided by operating activities	1,184	1,174
Add: Interest paid	273	255
Less: Interest capitalized to fixed and intangible assets	(139)	(127)
Add: Changes to non-cash working capital balances	(184)	(239)
FFO before interest	1,134	1,063
Adjusted Interest Expense		
Net interest expense	61	86
Add: Interest income	11	10
Add: Interest capitalized to fixed and intangible assets	139	127
Add: Interest related to regulatory assets and liabilities	92	66
Add: Interest on pension and OPEB projected benefit obligation less expected return on pension plan assets	156	92
Adjusted Interest Expense	459	381
FFO Interest Coverage (times)	2.5	2.8

(3) **Gross margin** is defined as revenue less fuel expense.

(4) **Earnings** are defined as net income.

Additional information about OPG, including its Annual Information Form, annual MD&A, and audited annual consolidated financial statements as at and for the year ended December 31, 2013 and notes thereto can be found on SEDAR at www.sedar.com.

For further information, please contact:

Investor Relations	416-592-6700 1-866-592-6700 investor.relations@opg.com
Media Relations	416-592-4008 1-877-592-4008

www.opg.com
www.sedar.com

ONTARIO POWER GENERATION INC.
INTERIM CONSOLIDATED FINANCIAL STATEMENTS
(unaudited)
SEPTEMBER 30, 2014



INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

	Three Months Ended September 30		Nine Months Ended September 30	
<i>(millions of dollars except where noted)</i>	2014	2013	2014	2013
Revenue (Note 12)	1,160	1,244	3,645	3,689
Fuel expense (Note 12)	161	186	464	541
Gross margin (Note 12)	999	1,058	3,181	3,148
Expenses (Note 12)				
Operations, maintenance and administration	595	684	1,931	2,027
Depreciation and amortization	184	243	546	727
Accretion on fixed asset removal and nuclear waste management liabilities	195	188	586	567
Earnings on nuclear fixed asset removal and nuclear waste management funds	(161)	(165)	(538)	(462)
Property and capital taxes	12	14	22	43
Income from investments subject to significant influence	(9)	(9)	(32)	(28)
Restructuring (Note 16)	3	46	15	48
	819	1,001	2,530	2,922
Income before other loss (income), interest, income taxes, and extraordinary item	180	57	651	226
Other loss (income)	-	-	2	(3)
Income before interest, income taxes, and extraordinary item	180	57	649	229
Net interest expense (Note 5)	15	18	38	63
Income before income taxes and extraordinary item	165	39	611	166
Income tax expense	46	9	133	35
Income before extraordinary item	119	30	478	131
Extraordinary item ¹ (Note 2)	243	-	243	-
Net income	362	30	721	131
Net income attributable to the Shareholder	361	30	718	131
Net income attributable to non-controlling interests (Note 17)	1	-	3	-
Basic and diluted net income per common share before extraordinary item (dollars)	0.46	0.12	1.87	0.51
Extraordinary item per common share (dollars)	0.95	-	0.95	-
Basic and diluted net income per common share (dollars)	1.41	0.12	2.80	0.51
Common shares outstanding (millions)	256.3	256.3	256.3	256.3

¹ Wholly attributable to the Shareholder.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (UNAUDITED)

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Net income	362	30	721	131
Other comprehensive income, net of income taxes (Note 7)				
Net gain (loss) on derivatives designated as cash flow hedges ¹	-	1	(3)	12
Recognition of pension and other post-employment benefits regulatory asset related to facilities prescribed for rate regulation as of July 1, 2014 ² (Note 2)	184	-	184	-
Reclassification to income of amounts related to pension and other post-employment benefits ³	5	10	24	32
Reclassification to income of losses from cash flow hedges ⁴	5	3	10	10
Other comprehensive income for the period	194	14	215	54
Comprehensive income	556	44	936	185
Comprehensive income attributable to the Shareholder	555	44	933	185
Comprehensive income attributable to non-controlling interests	1	-	3	-

¹ Net of income tax expense of \$1 million and nil for the three months ended September 30, 2014 and 2013, respectively. Net of income tax recoveries of \$1 million and income tax expense of \$3 million for the nine months ended September 30, 2014 and 2013, respectively.

² Net of income tax expense of \$61 million for the three and nine months ended September 30, 2014.

³ Net of income tax expenses of \$2 million and \$3 million for the three months ended September 30, 2014 and 2013, respectively. Net of income tax expenses of \$8 million and \$10 million for the nine months ended September 30, 2014 and 2013, respectively.

⁴ Net of income tax expense of nil for the three months ended September 30, 2014 and 2013, respectively. Net of income tax expense of \$1 million for the nine months ended September 30, 2014 and 2013, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 (millions of dollars)	2014	2013
Operating activities		
Net income	721	131
Adjust for non-cash items:		
Depreciation and amortization	546	727
Accretion on fixed asset removal and nuclear waste management liabilities	586	567
Earnings on nuclear fixed asset removal and nuclear waste management funds	(538)	(462)
Pension and other post-employment benefit costs (Note 8)	342	354
Deferred income taxes and other accrued charges	(186)	-
Provision for restructuring (Note 16)	10	48
Mark-to-market on derivative instruments	(95)	17
Provision for used nuclear fuel and low and intermediate level waste	85	80
Regulatory assets and liabilities	(47)	(177)
Provision for materials and supplies	16	13
Other	(12)	(15)
	1,428	1,283
Contributions to nuclear fixed asset removal and nuclear waste management funds	(104)	(136)
Expenditures on fixed asset removal and nuclear waste management	(147)	(144)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	55	58
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	(352)	(306)
Expenditures on restructuring (Note 16)	(23)	(4)
Net changes to other long-term assets and liabilities	20	61
Net changes to non-cash working capital balances (Note 13)	116	171
Cash flow provided by operating activities	993	983
Investing activities		
Investment in property, plant and equipment and intangible assets	(1,082)	(1,168)
Cash flow used in investing activities	(1,082)	(1,168)
Financing activities		
Issuance of long-term debt	200	515
Repayment of long-term debt	(2)	(2)
Distribution to non-controlling interests	(2)	-
Issuance of short-term notes	1,517	780
Repayment of short-term notes	(1,549)	(770)
Cash flow provided by financing activities	164	523
Net increase in cash and cash equivalents	75	338
Cash and cash equivalents, beginning of period	562	413
Cash and cash equivalents, end of period	637	751

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at (millions of dollars)	September 30 2014	December 31 2013
Assets		
Current assets		
Cash and cash equivalents	637	562
Receivables from related parties (Note 14)	345	402
Other accounts receivable and prepaid expenses	158	148
Nuclear fixed asset removal and nuclear waste management funds (Notes 6 and 12)	20	25
Fuel inventory (Note 12)	353	390
Materials and supplies (Note 12)	99	95
Regulatory assets (Note 3)	73	306
Income taxes recoverable	-	51
Deferred income taxes	42	-
	1,727	1,979
Property, plant and equipment (Note 12)	25,493	24,441
Less: accumulated depreciation	8,123	7,703
	17,370	16,738
Intangible assets (Note 12)	424	402
Less: accumulated amortization	353	343
	71	59
Other assets		
Nuclear fixed asset removal and nuclear waste management funds (Notes 6 and 12)	14,163	13,471
Long-term materials and supplies (Note 12)	337	330
Regulatory assets (Note 3)	5,891	5,094
Investments subject to significant influence (Note 15)	351	359
Other long-term assets	61	61
	20,803	19,315
	39,971	38,091

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at (millions of dollars)	September 30 2014	December 31 2013
Liabilities		
Current liabilities		
Accounts payable and accrued charges	992	1,026
Deferred revenue due within one year	12	12
Long-term debt due within one year (Note 4)	553	5
Short-term debt (Note 5)	-	32
Regulatory liabilities (Note 3)	-	16
Income taxes payable	9	-
Deferred income taxes	-	14
	1,566	1,105
Long-term debt (Note 4)	5,228	5,620
Other liabilities		
Fixed asset removal and nuclear waste management liabilities (Notes 6 and 12)	16,846	16,257
Pension liabilities	2,674	2,741
Other post-retirement benefit liabilities	2,710	2,628
Long-term accounts payable and accrued charges	525	653
Deferred revenue	204	180
Deferred income taxes	876	565
Regulatory liabilities (Note 3)	22	8
	23,857	23,032
Equity		
Common shares ¹	5,126	5,126
Retained earnings	4,610	3,892
Accumulated other comprehensive loss (Note 7)	(469)	(684)
Equity attributable to the Shareholder	9,267	8,334
Equity attributable to non-controlling interests (Note 17)	53	-
Total equity	9,320	8,334
	39,971	38,091

¹ 256,300,010 common shares outstanding at a stated value of \$5,126 million as at September 30, 2014 and December 31, 2013.

Commitments and Contingencies (Notes 4, 8, 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		
<i>(millions of dollars)</i>	2014	2013
Common shares	5,126	5,126
Retained earnings		
Balance at beginning of period	3,892	3,757
Net income attributable to the Shareholder	718	131
Balance at end of period	4,610	3,888
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of period	(684)	(979)
Other comprehensive income	215	54
Balance at end of period	(469)	(925)
Equity attributable to the Shareholder	9,267	8,089
Equity attributable to non-controlling interests (Note 17)		
Balance at beginning of period	-	-
Equity contribution from non-controlling interests	53	-
Distribution to non-controlling interests	(3)	-
Net income attributable to non-controlling interests	3	-
Balance at end of period	53	-
Total equity	9,320	8,089

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, 2014 and 2013

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2014 include the accounts of Ontario Power Generation Inc. (OPG or 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 interests. These interim consolidated financial statements have been prepared and presented in accordance with United States generally accepted accounting principles (US GAAP) and the rules and regulations of the United States Securities and Exchange Commission for interim financial statements. These interim 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, 2013. All dollar amounts are presented in Canadian dollars.

Certain of the 2013 comparative amounts have been reclassified from financial statements previously presented to conform to the 2014 interim consolidated financial statement presentation.

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. Information for the comparative period has been adjusted to reflect the changes to the reportable business segments. For further discussion, refer to Note 12, *Business Segments*.

Use of Management Estimates

The preparation of 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 during the reporting periods. Management evaluates the Company's estimates on an ongoing basis based on historical experience, current conditions and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in income in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits (OPEB), asset retirement obligations, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization, and inventories. Actual results may differ significantly from these estimates.

Seasonal Operations

OPG's quarterly results are affected by changes in demand primarily resulting from variations in seasonal weather conditions. Historically, OPG's revenues are 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. Regulated prices for most of OPG's baseload hydroelectric facilities and all of the nuclear facilities that OPG operates, cost recovery contracts and energy supply agreements, and OPG's hedging strategies significantly reduce the impact of seasonal price fluctuations on the results of operations.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Investment Companies

Effective January 1, 2014, OPG adopted the updated Accounting Standards Codification (ASC) Topic 946, *Financial Services – Investment Companies*. Based on the amended scope of the standard, certain entities and funds including the Decommissioning Segregated Fund (Decommissioning Fund) and the Used Fuel Segregated Fund (Used Fuel Fund) (together the Nuclear Funds) are treated as investment companies for accounting purposes. As the investments of these funds are already recorded at fair value, there were no measurement differences upon adoption of this update. OPG has provided the required additional disclosures in Note 6 of these interim consolidated financial statements.

Regulatory Assets Related to Newly Regulated Hydroelectric Facilities

Forty-eight of OPG's previously unregulated hydroelectric facilities were prescribed for rate regulation effective July 1, 2014. As a result, OPG recognized additional regulatory assets related to deferred income taxes, and unamortized amounts recorded in accumulated other comprehensive loss (AOCL) in respect of pension and OPEB obligations in the third quarter of 2014. The recognition of the increase in regulatory assets related to deferred income taxes resulted in a net extraordinary gain of \$243 million in the consolidated statements of income. The additional regulatory assets related to pension and OPEB obligations resulted in an increase of \$184 million in other comprehensive income, net of \$61 million in income taxes.

Recent Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers* (ASU 2014-09), which supersedes nearly all existing revenue recognition guidance, including industry-specific guidance under US GAAP. The core principle of ASU 2014-09 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. ASU 2014-09 defines a five step process to achieve this core principle and, in doing so, more judgement and estimates may be required compared to the requirements under existing US GAAP. The standard will be effective for OPG's 2017 fiscal year, including interim periods in 2017. In applying the standard, entities would have the option between two retrospective transition methods: (i) a full retrospective approach reflecting the application of the standard in each prior reporting period with the option to elect certain practical expedients, or (ii) a retrospective approach with the cumulative effect of initially adopting ASU 2014-09 recognized at the date of adoption and includes additional disclosures. OPG is currently assessing the impact of this new standard on its consolidated financial statements and has not yet determined the method by which it will adopt the standard in 2017.

3. REGULATORY ASSETS AND LIABILITIES

The regulatory assets and liabilities recorded as at September 30, 2014 and December 31, 2013 are as follows:

<i>(millions of dollars)</i>	September 30 2014	December 31 2013
Regulatory assets		
<i>Variance and deferral accounts as authorized by the Ontario Energy Board (OEB)</i>		
Pension and OPEB Cost Variance Account	917	667
Nuclear Liability Deferral Account	289	254
Bruce Lease Net Revenues Variance Account	284	353
Capacity Refurbishment Variance Account	185	100
Nuclear Development Variance Account	59	57
Nuclear Deferral and Variance Over/Under Recovery Variance Account	53	43
Other variance and deferral accounts	96	209
	1,883	1,683
Pension and OPEB Regulatory Asset (Note 8)	3,232	3,158
Deferred income taxes	849	559
Total regulatory assets	5,964	5,400
Less: current portion	73	306
Non-current regulatory assets	5,891	5,094
Regulatory liabilities		
<i>Variance and deferral accounts as authorized by the OEB</i>		
Other variance and deferral accounts	22	24
Total regulatory liabilities	22	24
Less: current portion	-	16
Non-current regulatory liabilities	22	8

As a result of 48 of OPG's previously unregulated hydroelectric facilities becoming prescribed for rate regulation effective July 1, 2014, additional regulatory assets were recognized during the third quarter of 2014. These regulatory assets relate to deferred income taxes and unamortized amounts recorded in accumulated other comprehensive loss in respect of pension and OPEB obligations. These amounts are expected to be recovered from customers through future regulated prices. As of July 1, 2014, the regulatory asset for deferred income taxes increased by \$324 million, including \$81 million related to the increase in deferred income tax liabilities resulting from the regulatory asset for deferred income taxes. As of July 1, 2014, the Pension and OPEB Regulatory Asset account increased by \$245 million.

As at September 30, 2014 and December 31, 2013, regulatory assets for other variance and deferral accounts included the Tax Loss Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account, the Hydroelectric Water Conditions Variance Account, and other variance accounts authorized by the OEB. As at September 30, 2014 and December 31, 2013, regulatory liabilities for other variance and deferral accounts included the Income and Other Taxes Variance Account and other variance accounts authorized by the OEB.

4. LONG-TERM DEBT

Long-term debt consists of the following:

<i>(millions of dollars)</i>	September 30 2014	December 31 2013
Notes payable to the Ontario Electricity Financial Corporation (OEFC)	3,965	3,965
UMH Energy Partnership debt	191	193
Lower Mattagami Energy Limited Partnership (LME) debt (Note 17)	1,625	1,467
	5,781	5,625
Less: due within one year	553	5
Long-term debt	5,228	5,620

In June 2014, the LME issued senior notes totalling \$200 million with a maturity date of 2024. The effective interest rate for these notes was 3.5 percent and the coupon interest rate was 3.4 percent.

In October 2014, the UMH Energy Partnership satisfied the conditions required by the financing for this project to limit recourse of bondholders to the assets of the project.

5. SHORT-TERM DEBT AND NET INTEREST EXPENSE

LME maintains a \$600 million bank credit facility to support the funding requirements of the Lower Mattagami River project. The facility consists of two \$300 million multi-year term tranches. During the third quarter of 2014, OPG extended the maturity of the first tranche to August 2019, from August 2018. The second tranche matures in August 2015. As at September 30, 2014, there was no commercial paper outstanding under this program (December 31, 2013 – \$32 million). In October 2014, \$100 million of commercial paper was issued.

The following table summarizes net interest expense:

<i>(millions of dollars)</i>	Three Months Ended September 30		Nine Months Ended September 30	
	2014	2013	2014	2013
Interest on long-term debt	75	70	219	206
Interest on short-term debt	2	-	3	2
Interest income	(3)	(3)	(8)	(7)
Interest capitalized to property, plant and equipment and intangible assets	(35)	(28)	(106)	(94)
Interest related to regulatory assets and liabilities ¹	(24)	(21)	(70)	(44)
Net interest expense	15	18	38	63

¹ Includes interest to recognize the cost of financing related to regulatory assets and liabilities and interest deferred in the Capacity Refurbishment Variance Account and the Bruce Lease Net Revenues 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, 2014 and December 31, 2013 consist of the following:

<i>(millions of dollars)</i>	September 30 2014	December 31 2013
Liability for nuclear used fuel management	10,341	9,957
Liability for nuclear decommissioning and low and intermediate level waste management	6,142	5,946
Liability for non-nuclear fixed asset removal	363	354
Fixed asset removal and nuclear waste management liabilities	16,846	16,257

Nuclear Funds

Beginning January 1, 2014, the Company applied ASC 946 for all investments owned by the Decommissioning Fund and the Used Fuel Fund. OPG's consolidated financial statements retained investment company accounting for the Nuclear Funds. The adoption of investment company accounting for the Nuclear Funds did not result in an effect on net income as investments held by OPG's Nuclear Funds continue to be recorded at fair value.

The investments in the Nuclear Funds are segregated from other assets in the consolidated group that are not investment companies.

The historical cost, gross unrealized aggregate appreciation and depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as at September 30, 2014 are summarized as follows:

<i>(millions of dollars)</i>	Decommissioning Fund	Used Fuel Fund ¹	Total
Historical cost	6,092	8,017	14,109
Unrealized gains			
Gross unrealized aggregate appreciation	1,092	1,290	2,382
Gross unrealized aggregate depreciation	(106)	(116)	(222)
Gross unrealized foreign exchange gains	53	84	137
	7,131	9,275	16,406
Due to Province	(957)	(1,266)	(2,223)
Total fair value	6,174	8,009	14,183
Less: current portion	7	13	20
Non-current fair value	6,167	7,996	14,163

¹ The Ontario NFWA Trust represented \$3,023 million as at September 30, 2014 of the Used Fuel Fund on a fair value basis.

The historical cost, gross unrealized aggregate appreciation and depreciation of investments, gross unrealized foreign exchange gains and fair value of the Nuclear Funds as at December 31, 2013 are summarized as follows:

<i>(millions of dollars)</i>	Decommissioning Fund	Used Fuel Fund ¹	Total
Historical cost	5,571	7,240	12,811
Unrealized gains			
Gross unrealized aggregate appreciation	1,111	1,365	2,476
Gross unrealized aggregate depreciation	(118)	(136)	(254)
Gross unrealized foreign exchange gains	27	50	77
	6,591	8,519	15,110
Due to Province	(624)	(990)	(1,614)
Fair value	5,967	7,529	13,496
Less: current portion	12	13	25
Non-current fair value	5,955	7,516	13,471

¹ The Ontario NFWA Trust represented \$2,668 million as at December 31, 2013 of the Used Fuel Fund on a fair value basis.

Net realized and unrealized gains or losses from investments for the nine months ended September 30, 2014 are summarized as follows:

<i>(millions of dollars)</i>	Decommissioning Fund	Used Fuel Fund	Total
Net realized gains			
Realized gains	354	484	838
Realized foreign exchange gains	38	39	77
Net realized gains	392	523	915
Net unrealized (losses) gains			
Unrealized losses	(7)	(55)	(62)
Unrealized foreign exchange gains	26	34	60
Net unrealized gains (losses)	19	(21)	(2)

Net realized and unrealized gains or losses from investments for the nine months ended September 30, 2013 are summarized as follows:

<i>(millions of dollars)</i>	Decommissioning Fund	Used Fuel Fund	Total
Net realized gains			
Realized gains	122	118	240
Realized foreign exchange losses	(6)	(4)	(10)
Net realized gains	116	114	230
Net unrealized gains			
Unrealized gains	183	311	494
Unrealized foreign exchange gains	39	44	83
Net unrealized gains	222	355	577

7. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of AOCL, net of income taxes, are as follows:

<i>(millions of dollars)</i>	Nine Months Ended September 30, 2014		
	Unrealized Gains and Losses on Cash Flow Hedges ¹	Pension and OPEB ¹	Total ¹
AOCL, beginning of period	(129)	(555)	(684)
Net loss on cash flow hedges	(3)	-	(3)
Net amounts reclassified from AOCL	10	24	34
Recognition of pension and OPEB regulatory asset related to facilities prescribed for rate regulation as of July 1, 2014 <i>(Note 2)</i>	-	184	184
Other comprehensive income for the period	7	208	215
AOCL, end of period	(122)	(347)	(469)

¹ All amounts are net of income taxes.

<i>(millions of dollars)</i>	Nine Months Ended September 30, 2013		
	Unrealized Gains and Losses on Cash Flow Hedges ¹	Pension and OPEB ¹	Total ¹
AOCL, beginning of period	(156)	(823)	(979)
Net gain on cash flow hedges	12	-	12
Net amounts reclassified from AOCL	10	32	42
Other comprehensive income for the period	22	32	54
AOCL, end of period	(134)	(791)	(925)

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, 2014 are as follows:

<i>(millions of dollars)</i>	Amount Reclassified from AOCL		Statement of Income Line Item
	Three Months Ended September 30, 2014	Nine Months Ended	
Amortization of losses from cash flow hedges			
Losses	5	11	Net interest expense
Income tax expense	-	(1)	
	5	10	
Amortization of amounts related to pension and OPEB			
Actuarial gains and past service costs	7	32	See (1) below
Income tax recoveries	(2)	(8)	
	5	24	
Total reclassifications for the period	10	34	

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, 2013 are as follows:

<i>(millions of dollars)</i>	Amount Reclassified from AOCL		Statement of Income Line Item
	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2013	
Amortization of losses from cash flow hedges			
Losses	3	11	Net interest expense
Income tax expense	-	(1)	
	<u>3</u>	<u>10</u>	
Amortization of amounts related to pension and OPEB			
Actuarial gains and past service costs	13	42	See (1) below
Income tax recoveries	(3)	(10)	
	<u>10</u>	<u>32</u>	
Total reclassifications for the period	13	42	

¹ These AOCL components are included in the computation of pension and OPEB costs (see Note 8 for additional details).

8. PENSION AND OPEB

OPG's total benefit costs for the three months ended September 30, 2014 and 2013 are as follows:

<i>(millions of dollars)</i>	Registered Pension Plans		Supplementary Pension Plans		OPEB	
	2014	2013	2014	2013	2014	2013
<i>Components of Cost Recognized</i>						
Current service costs	59	73	2	2	16	28
Interest on projected benefit obligation	165	147	4	4	34	35
Expected return on plan assets, net of expenses	(157)	(162)	-	-	-	-
Amortization of net actuarial loss ¹	65	61	1	2	2	11
Cost recognized ²	<u>132</u>	<u>119</u>	<u>7</u>	<u>8</u>	<u>52</u>	<u>74</u>

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, 2014 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of \$61 million (three months ended September 30, 2013 – \$61 million).

² These pension and OPEB costs for the three months ended September 30, 2014 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account of \$77 million (three months ended September 30, 2013 – \$82 million).

OPG's total benefit costs for the nine months ended September 30, 2014 and 2013 are as follows:

<i>(millions of dollars)</i>	Registered Pension Plans		Supplementary Pension Plans		OPEB	
	2014	2013	2014	2013	2014	2013
<i>Components of Cost Recognized</i>						
Current service costs	178	218	6	7	48	80
Interest on projected benefit obligation	494	442	11	10	101	105
Expected return on plan assets, net of expenses	(471)	(486)	-	-	-	-
Amortization of net actuarial loss ¹	195	183	3	5	5	36
Cost recognized ²	396	357	20	22	154	221

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, 2014 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of \$171 million (nine months ended September 30, 2013 – \$182 million).

² These pension and OPEB costs for the nine months ended September 30, 2014 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account of \$228 million (nine months ended September 30, 2013 – \$246 million).

A new actuarial valuation of the OPG registered pension plan was completed as of January 1, 2014 and was filed with the Financial Services Commission of Ontario in June 2014.

9. DERIVATIVES

OPG is exposed to risks related to changes in electricity prices associated with a wholesale spot market for electricity in Ontario, changes in market interest rates on debt expected to be issued in the future, and movements in foreign currency that affect its assets, liabilities, and forecasted transactions. Select derivative instruments are used to manage such risks, if required. 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 is undertaken by 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.

LME entered into forward start interest rate swaps to hedge against the effect of future changes in interest rates for the long-term debt supporting the Lower Mattagami River project. All interest rate exposures related to the forward start interest rate swaps have been eliminated since the second quarter of 2014.

Electricity price risk for the Company is the potential for adverse movements in the market price of electricity. Exposure to electricity price risk is reduced as a result of regulated prices and other contractual arrangements for a significant portion of OPG's business. The majority of this exposure should be mitigated with the implementation of a regulated price for OPG's 48 hydroelectric stations which were prescribed for rate regulation effective July 1, 2014.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Power lease agreement (Bruce Lease), is treated as a derivative. Assumptions related to future electricity prices impact the valuation of the derivative liability embedded in the Bruce Lease.

OPG's foreign exchange exposure is attributable to two primary factors: United States (US) dollar denominated transactions such as the purchase of fuels; and the influence of US dollar denominated commodity prices on Ontario electricity market prices. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the Company's exposure to foreign currency movements.

The majority of OPG's revenues are derived from sales through the Independent Electricity System Operator (IESO) administered spot 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, 2014 was less than \$1 million.

The following is a summary of OPG's derivative instruments:

<i>(millions of dollars except where noted)</i>	Notional Quantity	Terms	Fair Value	Balance Sheet Line Item
As at September 30, 2014				
Derivative embedded in the Bruce Lease	n/a	6 years	(255)	Long-term accounts payable and accrued charges
Other derivative instruments	various	various	6	Various
Total derivatives			(249)	

<i>(millions of dollars except where noted)</i>	Notional Quantity	Terms	Fair Value	Balance Sheet Line Item
As at December 31, 2013				
Derivative embedded in the Bruce Lease	n/a	6 years	(346)	Long-term accounts payable and accrued charges
Other derivative instruments	various	various	(8)	Various
Total derivatives			(354)	

Existing net losses of \$20 million deferred in AOCL as at September 30, 2014 are expected to be reclassified to net income within the next 12 months.

10. FAIR VALUE MEASUREMENTS

Fair value is the value that a financial instrument can be closed out or sold, in an arm's length transaction with a willing and knowledgeable counterparty.

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 significance of inputs used in measuring the fair value of the financial assets and liabilities. The level within which the financial asset or liability is classified is determined based on the attribute of significance to the inputs to the fair value measurement. 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 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.

For financial instruments which do not have quoted market prices 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 dates of the interim consolidated balance sheets. 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 were 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.

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 Company is required to determine the fair value of all its financial instruments. The following is a summary of OPG's financial instruments as at September 30, 2014 and December 31, 2013:

<i>(millions of dollars)</i>	Fair Value	Carrying Value ¹	Balance Sheet Line Item
As at September 30, 2014			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	14,183	14,183	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	(65)	(65)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(255)	(255)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(6,304)	(5,781)	Long-term debt
Other financial instruments	14	14	Various
As at December 31, 2013			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	13,496	13,496	Nuclear fixed asset removal and nuclear waste management funds
Payable related to cash flow hedges	(56)	(56)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(346)	(346)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,955)	(5,625)	Long-term debt
Other financial instruments	1	1	Various

¹ The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable and accounts payable and accrued charges approximate their fair value due to the immediate or short-term maturity of these financial instruments.

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 liabilities measured at fair value in accordance with the fair value hierarchy as at September 30, 2014 and December 31, 2013:

<i>(millions of dollars)</i>	September 30, 2014			
	Level 1	Level 2	Level 3	Total
Assets				
Decommissioning Fund	3,077	2,757	340	6,174
Used Fuel Fund	604	7,344	61	8,009
Other financial instruments	1	3	16	20
Total	3,682	10,104	417	14,203
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(255)	(255)
Other financial instruments	(5)	(1)	-	(6)
Total	(5)	(1)	(255)	(261)
Net assets	3,677	10,103	162	13,942

	December 31, 2013			
(millions of dollars)	Level 1	Level 2	Level 3	Total
Assets				
Decommissioning Fund	3,005	2,715	247	5,967
Used Fuel Fund	526	6,961	42	7,529
Other financial instruments	5	3	12	20
Total	3,536	9,679	301	13,516
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(346)	(346)
Other financial instruments	(8)	(11)	-	(19)
Total	(8)	(11)	(346)	(365)
Net assets (liabilities)	3,528	9,668	(45)	13,151

During the nine months ended September 30, 2014, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into and out of Level 3.

The following tables present the changes in OPG's assets and liabilities measured at fair value based on Level 3:

(millions of dollars)	For the three months ended September 30 2014			
	Decom- missioning Fund	Used Fuel Fund	Derivative Embedded in the Bruce Lease ¹	Other financial instruments
Opening balance, July 1, 2014	292	52	(182)	19
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds ¹	8	1	-	-
Unrealized losses included in revenue	-	-	(73)	(1)
Realized losses included in revenue	-	-	-	(3)
Purchases	40	8	-	1
Sales	(2)	-	-	-
Settlements	2	-	-	-
Closing balance, September 30, 2014	340	61	(255)	16

¹ Total gains exclude the impact of regulatory assets and liabilities.

(millions of dollars)	For the nine months ended September 30, 2014			
	Decom- missioning Fund	Used Fuel Fund	Derivative Embedded in the Bruce Lease ¹	Other financial instruments
Opening balance, January 1, 2014	247	42	(346)	12
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds ¹	22	4	-	-
Unrealized (losses) gains included in revenue	(4)	(1)	91	-
Realized losses included in revenue	-	-	-	(8)
Purchases	88	16	-	12
Sales	(3)	-	-	-
Settlements	(10)	-	-	-
Closing balance, September 30, 2014	340	61	(255)	16

¹ Total gains exclude the impact of regulatory assets and liabilities.

Derivative Embedded in the Bruce Lease

Due to a significant unobservable input used in the pricing model of the Bruce Lease embedded derivative, the measurement of the liability is classified within Level 3.

The following table presents the quantitative information about the Level 3 fair value measurement of the Bruce Lease embedded derivative as at September 30, 2014:

<i>(millions of dollars except where noted)</i>	Fair Value	Valuation Technique	Unobservable Input	Range
Derivative embedded in the Bruce Lease	(255)	Option model	Risk Premium ¹	0% - 30%

¹ Represents the range of premiums used in the valuation analysis that OPG has determined market participants would use when pricing the derivative.

The term related to the derivative embedded in the Bruce Lease is based on the remaining service lives, for accounting purposes, for certain units of the Bruce generating stations. OPG's exposure to changes in the fair value of the Bruce Lease embedded derivative is mitigated as part of the OEB regulatory process, since the revenue from the lease of the Bruce generating stations is included in the determination of regulated prices and is subject to the Bruce Lease Net Revenues Variance Account. As such, the pre-tax income statement impact, as a result of changes in the derivative liability, is offset by the pre-tax income statement impact of the Bruce Lease Net Revenues Variance Account.

Nuclear Funds

Nuclear Funds investments classified as Level 3 consist of real estate and infrastructure investments within the alternative investment portfolio. The fair value of the investments within the Nuclear Funds' alternative investment portfolio is determined using appropriate valuation techniques, such as recent arm's length market transactions, reference to current fair values of other instruments that are substantially the same, discounted cash flow analysis, 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 the 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 Funds that are reported on the basis of net asset value as at September 30, 2014:

<i>(millions of dollars except where noted)</i>	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Infrastructure	500	253	n/a	n/a
Real Estate	361	400	n/a	n/a
Pooled Funds				
Short-term Investments	12	n/a	Daily	1 - 5 Days
Fixed Income	555	n/a	Daily	1 - 5 Days
Equity	686	n/a	Daily	1 - 5 Days
Total	2,114	653		

The fair value of the above investments is classified as either Level 2 or Level 3.

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 the Nuclear 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 Funds may transfer any of its 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 investment in institutional-grade real estate property located in Canada. 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 the net asset value of the Nuclear Funds' ownership interest in these investments.

The partnership investments are not redeemable. However, the Nuclear Funds may transfer any of their partnership interests to another party, as stipulated in the partnership agreement, with prior written consent of the other limited partners. 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.

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 and fixed income securities. 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 the net asset value per share of the investments.

There are no significant restrictions on the ability to sell investments in this class.

11. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG or its subsidiaries covering a wide range of matters that arise in the ordinary course of its business activities.

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. 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 L.P. regarding an alleged breach of British Energy's representations and warranties to the claimants when they purchased British Energy's interest in Bruce Power L.P. (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 L.P.

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 L.P. 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".

Certain First Nations have commenced actions against OPG for interference with their respective reserve and traditional land rights. As well, OPG has been brought into certain actions by the First Nations against other parties as a third-party defendant.

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.

Environmental

Current operations are subject to regulation with respect to emissions to air, water, and land as well as other environmental matters by federal, provincial, and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its interim consolidated financial statements to meet certain other environmental obligations. As at September 30, 2014, OPG's environmental liabilities were \$15 million (December 31, 2013 – \$15 million).

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, 2014, the total amount of guarantees OPG provided to these entities was \$78 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. The fair value of these guarantees is negligible. As at September 30, 2014, OPG does not expect to make any payments associated with these guarantees.

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at September 30, 2014 are follows:

<i>(millions of dollars)</i>	2014	2015	2016	2017	2018	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	49	209	164	143	126	159	850
Contributions under the Ontario Nuclear Funds Agreement (ONFA) ¹	35	143	150	163	193	2,706	3,390
Long-term debt repayment	51	503	273	1,103	398	3,453	5,781
Interest on long-term debt	53	261	249	230	174	2,141	3,108
Unconditional purchase obligations	25	97	8	-	-	-	130
Operating lease obligations	11	16	15	15	13	68	138
Commitments related to Darlington refurbishment ²	200	-	-	-	-	-	200
Operating licence	10	23	24	24	18	-	99
Pension contributions to the OPG registered pension plan ³	90	364	370	-	-	-	824
Accounts Payable	315	-	-	-	-	-	315
Other	105	60	18	14	4	69	270
	944	1,676	1,271	1,692	926	8,596	15,105
Significant commercial commitments:							
Lower Mattagami	72	69	-	-	-	-	141
Atikokan	3	-	-	-	-	-	3
Total	1,019	1,745	1,271	1,692	926	8,596	15,249

¹ Contributions under the ONFA are based on the 2012 ONFA Reference Plan contribution schedule approved in 2012.

² Estimated currently committed costs to close the project, including demobilization of project staff and cancellation of existing contracts, and material orders.

³ The pension contributions include estimated minimum 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, 2014. The next actuarial valuation of the OPG registered pension plan must have an effective date no later than January 1, 2017. 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 2017 for the OPG registered pension plan 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.

12. BUSINESS SEGMENTS

Effective January 1, 2014, OPG revised the composition of its reportable business segments to reflect changes in its generation portfolio and its internal reporting. These changes primarily reflect 48 of OPG's hydroelectric generating facilities being prescribed for rate regulation effective July 1, 2014, and ending the use of coal at the Nanticoke and Lambton generating stations in 2013. OPG's reportable business segments, effective January 1, 2014, are as follows:

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Contracted Generation Portfolio
- Services, Trading, and other Non-Generation.

OPG's Regulated – Nuclear Generation and Regulated – Nuclear Waste Management segments are unchanged.

The Regulated – Hydroelectric segment continues to include the results of Sir Adam Beck 1, 2 and Pump generating station (GS), DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Beginning in the first quarter of

2014, this segment also includes the results of 48 hydroelectric stations which have been prescribed for rate regulation, effective July 1, 2014, under amended *Ontario Regulation 53/05*. The comparative information for the 48 hydroelectric stations, previously recorded under the Unregulated – Hydroelectric segment in OPG's third quarter 2013 MD&A and financial statements, has been reclassified to conform to this new presentation.

The Contracted Generation Portfolio segment includes the results of operating generation facilities that are not prescribed for rate regulation. The segment includes primarily generating facilities that are under an Energy Supply Agreement or other long-term contracts with the Ontario Power Authority (OPA).

Activities of generating stations that are not currently subject to a contract or rate regulation, but are available to generate electricity for sale, if required, are also included in the Contracted Generation Portfolio segment. Since the Lambton GS and Nanticoke GS were generating electricity up to the end of 2013, the activities related to these stations for the comparative period are reported in the Contracted Generation Portfolio segment. Effective January 1, 2014, the activities related to the Lambton GS and Nanticoke GS are reported under the Services, Trading, and other Non-Generation business segment. These stations ended coal-fired operations as a result of the Shareholder declaration issued in March 2013 mandating that OPG end the use of coal at these stations by the end of 2013.

The Contracted Generation Portfolio segment also includes OPG's share of equity income from its 50 percent ownership interests in the Portlands Energy Centre (PEC) and Brighton Beach. OPG's share of the in-service generating capacity and generation volume from its interests in the PEC and Brighton Beach stations are also included in this segment.

The Services, Trading, and other Non-Generation segment is a non-generation segment and 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, sales of financial risk management products, and sales of energy-related products. In addition, OPG has a wholly owned trading subsidiary that transacts solely in the US market. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in the revenue of this segment. In addition, this segment includes revenue from real estate rentals and other unregulated service revenues. The above activities were previously reported in the other segment.

Information for the comparative period has been adjusted to reflect the changes to OPG's reportable business segments and is labeled "adjusted".

Segment Income (Loss) for the Three Months Ended September 30, 2014 (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Manage- ment	Hydro- electric	Unregulated Contracted Generation Portfolio	Services, Trading, and other Non- Generation	Elimination	Total
Revenue	787	31	275	67	30	(30)	1,160
Fuel expense	65	-	91	5	-	-	161
Gross margin	722	31	184	62	30	(30)	999
Operations, maintenance and administration	444	32	80	43	26	(30)	595
Depreciation and amortization	128	-	40	11	5	-	184
Accretion on fixed asset removal and nuclear waste management liabilities	-	192	-	1	2	-	195
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(161)	-	-	-	-	(161)
Property and capital taxes	7	-	1	1	3	-	12
Income from investments subject to significant influence	-	-	-	(9)	-	-	(9)
Restructuring	-	-	-	1	2	-	3
Income (loss) before interest, income taxes, and extraordinary items	143	(32)	63	14	(8)	-	180

Segment Income (Loss) for the Three Months Ended September 30, 2013 <i>(millions of dollars)</i> <i>(adjusted)</i>	Regulated			Unregulated			Total
	Nuclear Generation	Nuclear Waste Manage- ment	Hydro- electric	Contracted Generation Portfolio	Services, Trading, and other Non- Generation	Elimination	
Revenue	749	31	294	190	10	(30)	1,244
Fuel expense	62	-	89	35	-	-	186
Gross margin	687	31	205	155	10	(30)	1,058
Operations, maintenance and administration	500	33	77	103	1	(30)	684
Depreciation and amortization	159	-	45	35	4	-	243
Accretion on fixed asset removal and nuclear waste management liabilities	-	185	-	3	-	-	188
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(165)	-	-	-	-	(165)
Property and capital taxes	6	-	1	4	3	-	14
Income from investments subject to significant influence	-	-	-	(9)	-	-	(9)
Restructuring	-	-	-	46	-	-	46
Income (loss) before interest, income taxes, and extraordinary items	22	(22)	82	(27)	2	-	57

Segment Income (Loss) for the Nine Months Ended September 30, 2014 (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Manage- ment	Hydro- electric	Unregulated Contracted Generation Portfolio	Services, Trading, and other Non- Generation	Elimination	Total
Revenue	2,178	89	1,087	224	153	(86)	3,645
Fuel expense	181	-	249	32	2	-	464
Gross margin	1,997	89	838	192	151	(86)	3,181
Operations, maintenance and administration	1,457	94	241	129	96	(86)	1,931
Depreciation and amortization	387	-	122	22	15	-	546
Accretion on fixed asset removal and nuclear waste management liabilities	-	575	-	5	6	-	586
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(538)	-	-	-	-	(538)
Property and capital taxes	21	-	1	(2)	2	-	22
Income from investments subject to significant influence	-	-	-	(32)	-	-	(32)
Restructuring	-	-	-	8	7	-	15
Other loss	-	-	2	-	-	-	2
Income (loss) before interest, income taxes, and extraordinary items	132	(42)	472	62	25	-	649

Segment Income (Loss) for the Nine Months Ended September 30, 2013 <i>(millions of dollars)</i> <i>(adjusted)</i>	Regulated			Unregulated			Total
	Nuclear Generation	Nuclear Waste Manage- ment	Hydro- electric	Contracted Generation Portfolio	Services, Trading, and other Non- Generation	Elimination	
Revenue	2,181	84	931	524	50	(81)	3,689
Fuel expense	181	-	249	111	-	-	541
Gross margin	2,000	84	682	413	50	(81)	3,148
Operations, maintenance and administration	1,490	90	218	307	3	(81)	2,027
Depreciation and amortization	470	-	137	106	14	-	727
Accretion on fixed asset removal and nuclear waste management liabilities	-	556	-	10	1	-	567
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(462)	-	-	-	-	(462)
Property and capital taxes	21	-	2	11	9	-	43
Income from investments subject to significant influence	-	-	-	(28)	-	-	(28)
Restructuring	-	-	-	48	-	-	48
Other loss (income)	(1)	-	2	(2)	(2)	-	(3)
Income (loss) before interest, income taxes, and extraordinary items	20	(100)	323	(39)	25	-	229

Selected Consolidated Balance Sheet Information as at September 30, 2014 (millions of dollars)	Regulated			Unregulated		Total
	Nuclear Generation	Nuclear Waste Manage- ment	Hydro- electric	Contracted Generation Portfolio	Services, Trading, and other Non- Generation	
Segment property, plant and equipment in-service, net	4,652	-	7,561	2,305	336	14,854
Segment construction in progress	1,450	-	89	921	56	2,516
Segment property, plant and equipment, net	6,102	-	7,650	3,226	392	17,370
Segment intangible assets in-service, net	12	-	1	4	16	33
Segment development in progress	1	-	-	-	37	38
Segment intangible assets, net	13	-	1	4	53	71
Segment materials and supplies inventory, net:						
Current	99	-	-	-	-	99
Long-term	330	-	1	6	-	337
Segment fuel inventory	316	-	-	37	-	353
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	14,183	-	-	-	14,183
Fixed asset removal and nuclear waste management liabilities	-	(16,483)	-	(331)	(32)	(16,846)

Selected Consolidated Balance Sheet Information as at December 31, 2013 (millions of dollars) (adjusted)	Nuclear Generation	Regulated Nuclear Waste Manage- ment	Hydro- electric	Contracted Generation Portfolio	Unregulated Services, Trading, and other Non- Generation	Total
Segment property, plant and equipment in-service, net	4,864	-	7,624	921	189	13,598
Segment construction in progress	866	-	81	2,150	43	3,140
Segment property, plant and equipment, net	5,730	-	7,705	3,071	232	16,738
Segment intangible assets in-service, net	15	-	1	4	17	37
Segment development in progress	2	-	-	-	20	22
Segment intangible assets, net	17	-	1	4	37	59
Segment materials and supplies inventory, net:						
Current	94	-	-	1	-	95
Long-term	322	-	1	7	-	330
Segment fuel inventory	334	-	-	56	-	390
Nuclear fixed asset removal and nuclear waste management funds (current and non-current portions)	-	13,496	-	-	-	13,496
Fixed asset removal and nuclear waste management liabilities	-	(15,903)	-	(322)	(32)	(16,257)

13. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

<i>(millions of dollars)</i>	Nine Months Ended September 30	
	2014	2013
Receivables from related parties	57	58
Other accounts receivable and prepaid expenses	(12)	(1)
Fuel inventory	37	88
Income taxes payable/recoverable	60	30
Materials and supplies	(4)	1
Accounts payable and accrued charges	(22)	(5)
	116	171

14. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, related parties include the Province, the OPA and the other successor entities of Ontario Hydro, including Hydro One Inc. (Hydro One), the IESO, and the OEFC. Related parties also include OPG's jointly controlled entities. The transactions between OPG and the related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The related party balances, as at September 30, 2014 and December 31, 2013, are summarized below:

<i>(millions of dollars)</i>	2014	2013
Receivables from related parties		
Hydro One	1	2
IESO	311	317
OEFC	10	67
OPA	20	14
PEC	3	2
Accounts payable and accrued charges		
Hydro One	4	3
OEFC	28	51
Province	3	2

15. 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. Details of the balances as at September 30, 2014 and December 31, 2013 are as follows:

<i>(millions of dollars)</i>	2014	2013
PEC		
Current assets	15	19
Long-term assets	290	303
Current liabilities	(5)	(15)
Long-term liabilities	(4)	(4)
Brighton Beach		
Current assets	5	5
Long-term assets	189	196
Current liabilities	(12)	(11)
Long-term liabilities	(6)	(5)
Long-term debt	(121)	(129)
Investments subject to significant influence	351	359

16. RESTRUCTURING

In response to the Ministry of Energy's Long-Term Energy Plan, Supply Mix Directive and various other directives, OPG has been undertaking restructuring activities since 2011 pertaining to the closure of its coal-fired generating units at the Lambton GS, Nanticoke GS, Atikokan GS and Thunder Bay GS. These activities have an impact on staff requirements and require OPG to record the corresponding restructuring costs.

In December 2013, the Minister of Energy issued a Directive to the OPA to negotiate and enter into a contract for electricity from one unit at the Thunder Bay GS using advanced biomass fuel. The impact on staff requirements has been finalized. The total restructuring costs, exclusively severance costs, are estimated to be \$8 million and were recorded during the second and third quarters of 2014. Relocation costs are expected to be minimal and will be recorded as incurred, primarily in 2015.

OPG conducted discussions with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements, at all plants impacted to date by the regulation requiring the cessation of

coal-fired electricity generation. Given collective agreement provisions allowing deferral of severance payout to future periods, the restructuring liability is expected to be fully drawn down by 2017.

The change in the restructuring liability for severance costs for the nine months ended September 30, 2014 and for the year ended December 31, 2013 is as follows:

<i>(millions of dollars)</i>	
Liability, January 1, 2013	3
Restructuring charges during the year	50
Payments during the year	(13)
Liability, December 31, 2013	40
Restructuring charges during the period	10
Payments during the period	(23)
Liability, September 30, 2014	27

17. NON-CONTROLLING INTEREST

Lower Mattagami Limited Partnership (LMLP) is an Ontario limited partnership between OPG, Amisk-oo-Skow Finance Corporation (AFC), a corporation wholly owned by the Moose Cree First Nation, and LM Extension Inc., a wholly owned subsidiary of OPG. The principal business of LMLP is the development, construction, ownership, operation and maintenance of hydroelectric generating facilities located on the Lower Mattagami River. As incremental units are placed in-service, the AFC may acquire up to a 25 percent interest in the value of the assets through its investment in LMLP.

The Little Long GS and Harmon GS were declared in-service in January 2014 and June 2014, respectively. Subsequent to the units' in-service dates, the AFC acquired a 25 percent interest in the value of the incremental assets of the Lower Mattagami River project. OPG consolidates the results of LMLP in its consolidated financial statements and the non-controlling interest represents the AFC's ownership interest in LMLP. Units 1 and 2 of the Smoky Falls GS were declared in-service on September 30, 2014 and October 9, 2014, respectively. The AFC acquired additional 25 percent interest in the value of these incremental assets in October 2014 and made equity contributions to LMLP for Unit 1 and Unit 2, respectively.