Ontario

MINISTRY OF
ENERGY

Proposed Initiatives to Transform Ontario's Electricity Sector – Update

Working Draft

December 2016

CONFIDENTIAL DRAFT

Context

- Electricity costs are increasing as the necessary investments are made to decarbonize and modernize the province's electricity infrastructure (i.e., $35 billion+ investment in cleaner generation and $15.5 billion investment in Hydro One transmission and distribution systems).

- Ontario has taken a number of actions to lower electricity cost for all consumers by:
  - Deferring investments in generation (e.g., new build nuclear), improving market efficiency (e.g., wind dispatch) and decreasing the cost of renewable procurements (e.g., GEIA renegotiation, decreasing FIT prices).
  - Increasing cost effectiveness and improving efficiency by adopting new electricity market approaches (e.g., competitive LRP, no new NUG contracting).

- Following the 2016 Throne Speech, actions were announced to further reduce electricity costs by:
  - Providing an 8% rebate ($11/month savings), updating RRRP ($45/month savings), expanding ICI (up to one-third savings for participants), suspending the LRP II and the EFWSOP (up to $3.8 billion in cost savings) and recycling proceeds to industrial/ commercial consumers.

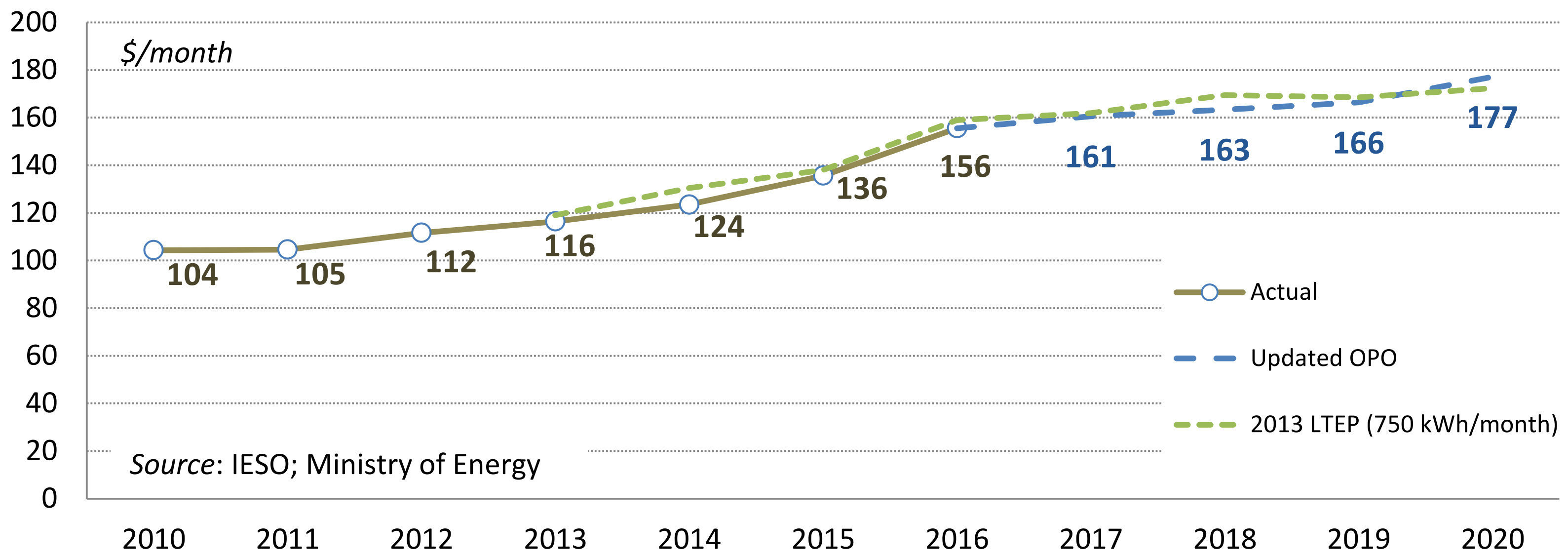
- On November 28, 2016, the Minister of Energy announced the need for changes in how electricity resources are procured, the need for wholesale market renewal and greater electricity consumer choice.

- The Ministry of Energy is currently updating its Long-Term Energy Plan (LTEP), which provides an opportunity to consider a range of policy changes to how the Ontario energy sector operates.

Electricity Prices – Residential

- Residential consumers electricity prices continue to be a concern for many Ontarians, particularly those that rely on electric heat.
  - **Note:** The typical residential bill is currently below the 2013 Long-Term Energy Plan (2013 LTEP) forecast.

Typical Residential Electricity Bills
Historical and Forecast



Note: The 2013 LTEP forecast for residential bills was based on 800 kWh/month without RRRP or electric heating; the above has been rebased to 750 kWh/month for comparison purposes. Typical residential are based on Toronto Hydro. The updated OPO forecast above includes the 8% rebate to offset the provincial portion of HST, ICI expansion and RRRP expansion.

Broad Policy Themes / Rationale

- Support the continued reduction in the differential across distribution rates (as charged by Local Distribution Companies) across the Province through the potential enhancement of Rural or Remote Electricity Rate Protection, (RRRP). In order to not increase regulatory costs to customers as a result, this program can be moved to the tax-base.
- Provide a greater focus and support on lower income Ontarians by funding the Ontario Electricity Support Program (OESP) through the tax-base, as well as enhancing the support available through the program.
- Amortize electricity conservation and demand management (DM) programs over 15-years to provide lower costs for electricity consumers.
  - Alternatively, pay for conservation/DM programs through the tax-base and transition costs to the new "green bank entity" over time. Costs would be shifted in recognition of the burden borne by ratepayers in phasing out coal generation.
- Expand the scope of the "Trillium Trust" to make investments in energy infrastructure eligible for funding, such as remote electrification, large transmission projects, new or expanded interties and expansion of natural gas to underserved areas (i.e., rural and remote communities), etc.
- Empower energy agencies to increase cost effectiveness and improve efficiency by having – IESO modernize Ontario's electricity market through electricity market renewal initiatives, the OEB identify opportunities for future LDC cost reductions/efficiencies and work with OPG to find further efficiencies in operations and pass on savings to ratepayers.
- Give consumers more choice by allowing households to "opt into" an alternative rate plan, based on a flat electricity rate, as an interim measure as the Ontario Energy Board (OEB) develops more pricing options over time. Also give consumer greater transparency with respect to electricity costs by providing more details regarding the Global Adjustment (GA).
- Help small business manage their electricity costs and provide relief for cap and trade until proceeds recycling is fully operational by ending the Debt Retirement Charge (DRC) early for commercial and small industrial Class B electricity consumers, a benefit of $7/MWh.

Proposed Initiatives – Potential Savings for Typical Residential Electricity Consumers

$/750kWh	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Timing of Benefit**
Recommended Initiatives							
1. Fund RRRP through the Tax-Base ***	1.53	1.58	1.61	1.66	1.70	1.74	Immediate
2. Fund OESP through the Tax-Base***	0.57	0.79	0.98	1.13	1.29	1.44	Immediate
a. Enhance OESP Benefit	-	-	-	-	-	-	n/a
b. Expand OESP Eligibility	-	-	-	-	-	-	n/a
3. Conservation Funding Options							
a. Amortize Conservation Program Costs (15-Year Amortization) b. Rate Smoothing of Conservation Program Costs (same impact as amortization)	1.62	1.88	1.16	1.20	0.82	0.69	Immediate
4. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, natural gas expansion, etc.)	-	-	-	2.16	2.16	2.17	Medium to Long-Term
5. Dedicate Departure Tax	1.39	1.39	1.39	1.39	1.39	1.39	Immediate
6. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency							
a. IESO – Market Renewal	-	-	-	-	1.00	1.03	Long-Term
b. OEB – LDC Efficiencies/Rates*	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
c. OPG – Operational Efficiencies	0.71	0.89	1.08	1.22	1.35	1.24	Immediate
7. Give Residential Consumers More Rate Choices and Greater Transparency	-	-	-	-	-	-	n/a
8. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a
9. Extend Length of Existing Wind /Solar Contracts at Lower Prices	TBD	TBD	TBD	TBD	TBD	TBD	TBD
10. v Tax Relief for Solar and Wind Contracts	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended							
Fund Conservation Programs Through The Tax-Base	3.47	3.83	3.17	3.35	2.84	2.90	Immediate
Eliminate the Industrial Conservation Initiative (ICI)	4.40	4.24	4.10	4.24	3.73	3.58	Immediate

Note: The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 2 assumes OESP participation of 50% and 5-year maturity. *Assessing the range of ratepayer impacts will be done through the LTEP development and implementation process in conjunction with the OEB. **Class B includes small-medium enterprises (SMEs). ***RRRP and OESP numbers are assumed to be at status quo.

Proposed Initiatives – Potential Savings for Average Industrial Electricity Consumers

$/MWh	2017	2018	2019	2020	2021	2022	Timing of Benefit
Recommended Initiatives							
1. Fund RRRP through the Tax-Base ***	2.04	2.10	2.15	2.22	2.27	2.32	Immediate
2. Fund OESP through the Tax-Base***	0.76	1.05	1.31	1.51	1.71	1.92	Immediate
a. Enhance OESP Benefit	-	-	-	-	-	-	n/a
b. Expand OESP Eligibility	-	-	-	-	-	-	n/a
3. Conservation Funding Options							
a. Amortize Conservation Program Costs (15-Year Amortization) b. Rate Smoothing of Conservation Program Costs (same impact as amortization)	1.12	1.30	0.80	0.83	0.57	0.47	Immediate
4. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, natural gas expansion, etc.)	-	-	-	1.79	1.79	1.79	Medium to Long-Term
5. Dedicate Departure Tax	1.86	1.86	1.86	1.86	1.86	1.86	Immediate
6. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency							
a. IESO – Market Renewal	-	-	-	-	1.34	1.38	Long-Term
b. OEB – LDC Efficiencies / Rates*	TBD	TBD	TBD	TBD	TBD	TBD	Medium-Term
c. OPG – Operational Efficiencies	0.59	0.74	0.89	1.01	1.12	1.03	Immediate
7. Give Residential Consumers More Rate Choices and Greater Transparency	-	-	-	-	-	-	n/a
8. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)**	-	-	-	-	-	-	n/a
9. Extend Length of Existing Wind /Solar Contracts at Lower Prices	TBD	TBD	TBD	TBD	TBD	TBD	TBD
10. Tax Relief for Solar and Wind Contracts	TBD	TBD	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended							
Fund Conservation Programs Through The Tax-Base	2.88	3.17	2.66	2.77	2.36	2.41	Immediate
Eliminate the Industrial Conservation Initiative (ICI)	(24.12)	(23.21)	(22.45)	(23.23)	(20.42)	(19.61)	Immediate
[illegible]							

Note: The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 2 assumes OESP participation of 50% and 5-year maturity. *Assessing the range of ratepayer impacts will be done through the LTEP development and implementation process in conjunction with the OEB. **Class B includes small-medium enterprises (SMEs). ***RRRP and OESP numbers are assumed to be at status quo.

Proposed Taxpayer Funded Electricity Price Mitigation

$M	2016-17[1]	2017-18[1]	2018-19[1]	2019-20[1]	2020-21[1]
Recommended Initiatives					
1. Fund RRRP through the Tax-Base*	-	666	684	700	719
2. Fund OESP through the Tax-Base					
a. Enhance OESP Benefit		162	226	279	322
b. Expand OESP Eligibility		TBD	TBD	TBD	TBD
3. Conservation Funding Options					
a. Amortize Conservation Program Costs (15-Year Amortization) b. Rate Smoothing of Conservation Program Costs (same impact as amortization)	-	-	-	-	-
4. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, natural gas expansion, etc.)	100	390	390	390	390
5. Dedicate Departure Tax	260	260	260	260	260
6. Empower Energy Agencies to Increase Cost Effectiveness and Improve Efficiency					
a. IESO – Market Renewal	-	-	-	-	-
b. OEB – LDC Efficiencies / Rates	-	-	-	-	-
c. OPG – Operational Efficiencies	-	-	-	-	-
7. Give Residential Consumers More Rate Choices and Greater Transparency	-	-	-	-	-
8. Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)	110	450	-	-	-
9. Extend the Length of Existing Wind/Solar Contracts at Lower Prices	-	-	-	-	-
10. Tax Relief for Solar and Wind Contracts	TBD	TBD	TBD	TBD	TBD
Considered but not Recommended					
Fund Conservation Programs Through The Tax-Base	154	632	649	567	568
Eliminate the Industrial Conservation Initiative (ICI)	-	-	-	-	-
Cancel LRP I	-	-	-	-	-

Source: Ministry of Finance, Energy
Note: *Assumes RRRP enhancement to reduce distribution rates to $30 for LDCs and **Assumes increase OESP credit by 50%.
Not included in chart is additional $18M/year to fund potential First Nations rate program through the Tax-Base.

Existing Rate Mitigation Programs – Overview

- There are a number of existing programs funded by electricity ratepayers that help mitigate electricity bills for some customers, each of which has a unique policy rationale.

- Programs such as the as the Rural or Remote Rate Protection (RRRP) program are targeted at all customers who face the highest delivery costs in the province, while others such as the Ontario Electricity Support Program (OESP), are income tested and targeted at the most vulnerable energy consumers.
  - These program are not mutually exclusive and a customer could receive both the RRRP and the OESP.
  - There are other programs that are still under development such as options for a First Nations Rate currently being developed by the OEB as per the request of the Minister of Energy. These options are aimed to alleviate high delivery costs for on-reserve indigenous consumers.

- There are opportunities to enhance each of these programs. However, if enhancements are funded through the electricity rate-base, while they would lower costs for eligible consumers, they would raise costs for all other ratepayers.

- Given that these programs focus on promoting equity between different areas of the province (RRRP) or on social equity (OESP), they could be funded by the tax-base rather than the rate-base. This would allow their goals to be achieved and enhanced without increasing electricity rates. The following slides explore options to enhance each program using the tax-base.
  - These enhancements would also work in conjunction with the Ontario Energy Board's focus on reducing LDC costs outlined in option 6b.

1. Rural or Remote Rate Protection (RRRP) Expansion

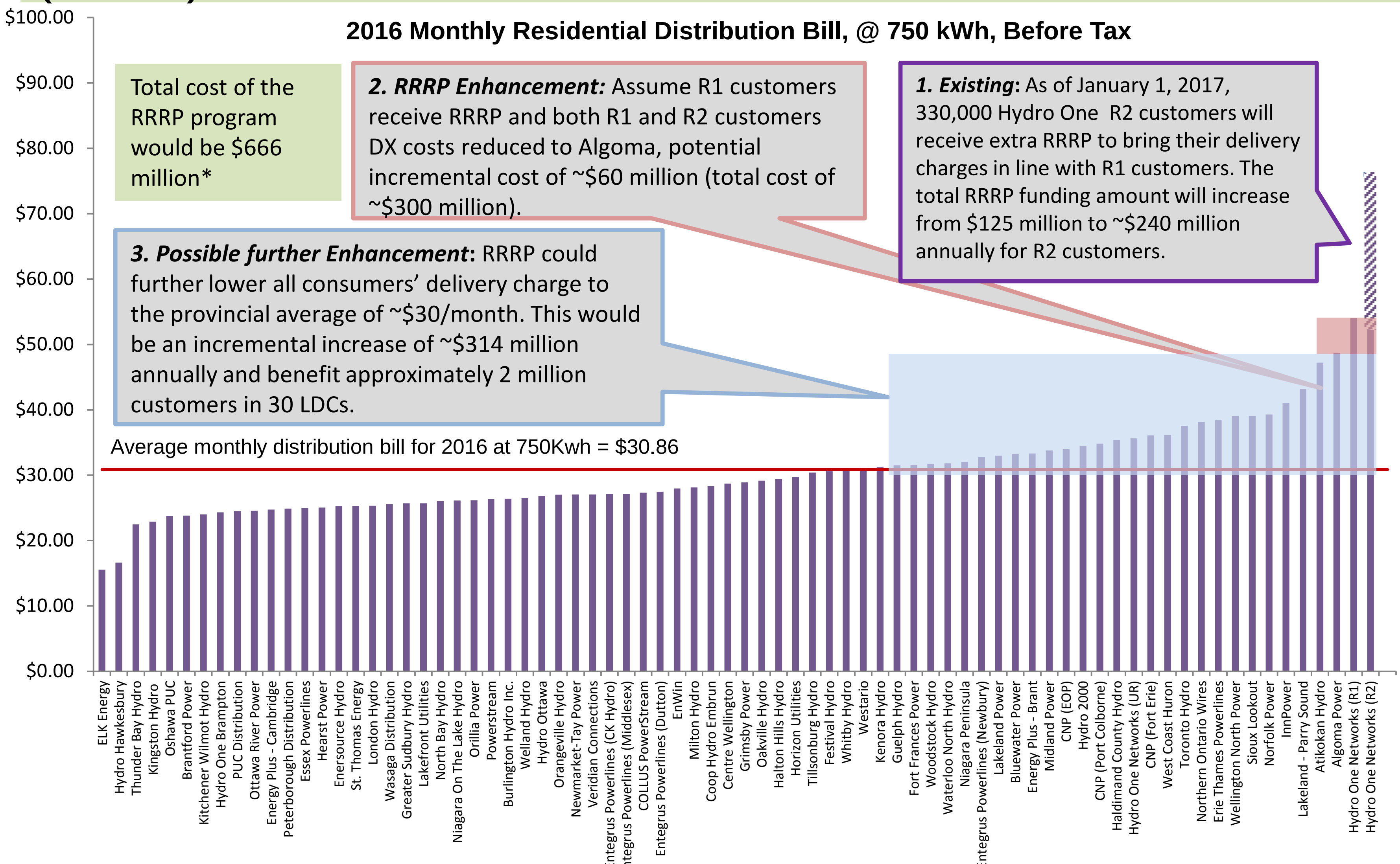
- The Rural or Remote Rate Protection (RRRP) program supports the most costly-to-serve distribution customers in Ontario. It is not income tested and most of the support goes to Hydro One's R2 (low density) rate class and remote communities.
  - Costs to these Hydro One customers are higher than average because of their relatively low density. The OEB mandates that they pay the full cost of service and in recent rate filings has asked Hydro One to ensure this through cost allocation studies.
  - To mitigate these costs, the RRRP was recently enhanced to help lower the bills of Hydro One's R2 customers to around those of its R1 (medium density) customers.
- Although other LDCs do not have medium- and high-density rates, there is a wide range of distribution costs between LDCs. The RRRP could be expanded to mitigate delivery costs for not only Hydro One customers but other high-cost LDCs.
  - Could be done on its own or as part of exploring an Ontario-wide uniform "postage stamp" delivery rate.

Considerations

- RRRP will be enhanced for R2 customers on January 1, 2017 to have their costs reduced to approximately R1 distribution costs levels. The RRRP could be further enhanced to include R1 customers, and have R2 and R1 customers reduce their costs down to Algoma (see next slide). This would cost $300 million in the first year (and would adjust year over year).
- If there was a desire to reduce costs for all LDCs, a simple average of distribution cost before tax, across all rate zones is $30.86 per month, for a residential customer consuming 750 kWh per month.** Bringing all delivery rates down to this average would cost approximately $500 million for the first year, with escalation in line with average distribution rate increases.
  - This assumes Hydro One R2 consume 1,200 kWh and H1 R1 customers consume 1,000 kWh per month.
- If all customers were brought down to the average costs (see the chart on the next slide for more detail):
  - It is assumed that residential customers with bills less than the provincial average see no change;
  - Majority of the enhanced benefit would go to Hydro One R1 and Toronto Hydro customers; and
  - Mechanism to ensure that LDCs continue to be motivated to achieve efficiencies would need to be designed (see section 4).
- Enhanced RRRP support may be best provided from the tax-base, because if funded from the rate-base, it would increase the costs for all customers who may argue that it is unfair that they are being asked to pay more to subsidize those in other LDCs.
- In conjunction with using the tax-base to reduce delivery charges to the provincial average, the OEB could be asked to explore moving to a province-wide "postage stamp" delivery rate that would be the same across the province to be implemented over time.
  - Could be "winners and losers" as delivery rates less than the average would go up in a postage stamp model;
  - A "postage stamp" model could help incent LDC consolidation.

Note: This is based on preliminary estimates and the amount will fluctuate on monthly consumption from customers and LDCs have different customer base with different consumption types.

1. Rural or Remote Rate Protection (RRRP) Expansion (cont'd)



Note: this includes the ~$50M currently supporting Algoma Power and Hydro One Remotes.

2a. Enhance Ontario Electricity Support Program (OESP) Benefit

- The OESP is an income-tested, application based program that lowers the electricity costs of the most vulnerable consumers by providing a rebate directly on their electricity bills. The OESP provides basic benefits to most consumers and enhanced benefits to Indigenous customers and customers with electric heat and medical devices and at launch, it was estimated ~560,000 families could be eligible and some 261,000 applications have been submitted.

- The OESP program benefits could be increased across the board by 50%, which would mean:
  - Single low income consumers would see an increase from $30 to $45/ month ($540/year); and
  - Families of four with electric heat could see an increase from $55 to $82.50/month ($990/year).

- The OESP program could also be further enhanced by working to ensure the program uptake is as close as possible to 100%:
  - Streamlining the application process to make it easier and quicker to get through;
  - Putting in place a more aggressive communications strategy to make sure people are aware of the program;
  - Increasing funding for key partner agencies to work directly with individuals who are applying; and
  - Exploring automatic OESP qualification for those who receive provincial programs (e.g., ODSP).

<u>Considerations</u>

- If the OESP was funded by the tax-base, it could also be explored whether the OESP could be better delivered as a provincial program via the tax system. This may help ensure that the program's participation rate is as high as possible.
  - At the time of program design, advice was given that a 40-50% participation rate would be high for an application-based program delivered through electricity bills.
  - The province would need to work with LDCs if the rebate was to appear on electricity bills rather than be delivered via the income tax system (e.g., through the Trillium Benefit).

1 & 2a. Fiscal Impacts of RRRP, OESP and First Nation Rate

- Table below shows estimates of program costs up to 2022:

Year	OESP ($M)	OESP + 50%($M)	RRRP($M)	RRRP Enhancement ($M)	First Nations Delivery Rate($M)	TOTAL RANGE ($M) (from status quo to OESP and RRRP enhancements)
2017	$108	$162	$292	$374	$18	$418 to $846
2018	$150	$226	$300	$384	$18	$468 to $928
2019	$186	$279	$306	$394	$18	$510 to $997
2020	$215	$322	$315	$404	$18	$548 to $1,059
2021	$243	$365	$322	$415	$18	$583 to $1,120
2022	$272	$408	$329	$426	$18	$619 to $1,181

1) Ontario Electricity Support Program (OESP)
   - After almost a year in market, close to 30% of potentially eligible customers are signed up.
   - The cost projections above assume the program grows to 100% of eligible consumers by 2022 and remains at that level.
   - The second column forecast also assumes the existing credit amounts increase by 50%.
     - Forecast assumes 10% administration costs
     - Forecast does not account for the approximately 142,000 low-income households that OEB estimated are not eligible because they do not directly receive an electricity bill.

2) Rural and Remote Rate Protection (RRRP)
   - Provides benefits to R2 Hydro One consumers, Algoma, and remote communities.
   - Includes the expanded coverage that will begin on January 1, 2017.
   - Expansion to cap distribution rates for other customers is based at $374M and assumes escalation of 2.6% (historical average dx rate increase). This is a conservative estimate, as Hydro One and Toronto Hydro increases could drive program costs beyond the average increase.

3) First Nation rate reduction (currently under development)
   - On November 14, 2016, OEB presented options to the Ministry on reducing costs for on-reserve First Nation customers.
   - OEB's recommended option to provide 100% delivery rate credit, which is estimated at $18.4 million per year.
     - Other options includes a seasonal fixed credit to account for demand changes over the year ($13 million) or a 50% total bill reduction ($23 million).

2b. Expand OESP Eligibility

Expanded Coverage

- When OESP was being created, the OEB estimated that are 713,000 low-income households, of which 20% do not receive electricity bills. Thus, only 571,000 would potentially be eligible for OESP.
- If moved to the tax base, the OESP could be broadened to include all potential low-income households, despite whether they directly pay for electricity.

Eligibility Categories

- OESP has two credits amounts:
  1) Basic credit of $30-50 per month, based on the level of income and the number of residents.
  2) Enhanced credit of $45-75 per month for those with unique electricity needs:
     a) Electric heating,
     b) Indigenous customers, and
     c) Certain electrically intensive medical devices.
- The enhanced credit can be expanded to include additional eligibility categories of customers. For example, a new "Low Density Consumer" category could be introduced that provides Hydro One R2 customers (highest distribution rates) eligible for OESP the enhanced credit.

Considerations

- Potential costs for expanded coverage and new eligibility categories depend on updated estimates and changes to program design and delivery.
- There would be value in keeping the OESP as an income-tested program to distinguish it from other initiatives (e.g. RRRP, which is designed to address disparity between rural and urban distribution costs).

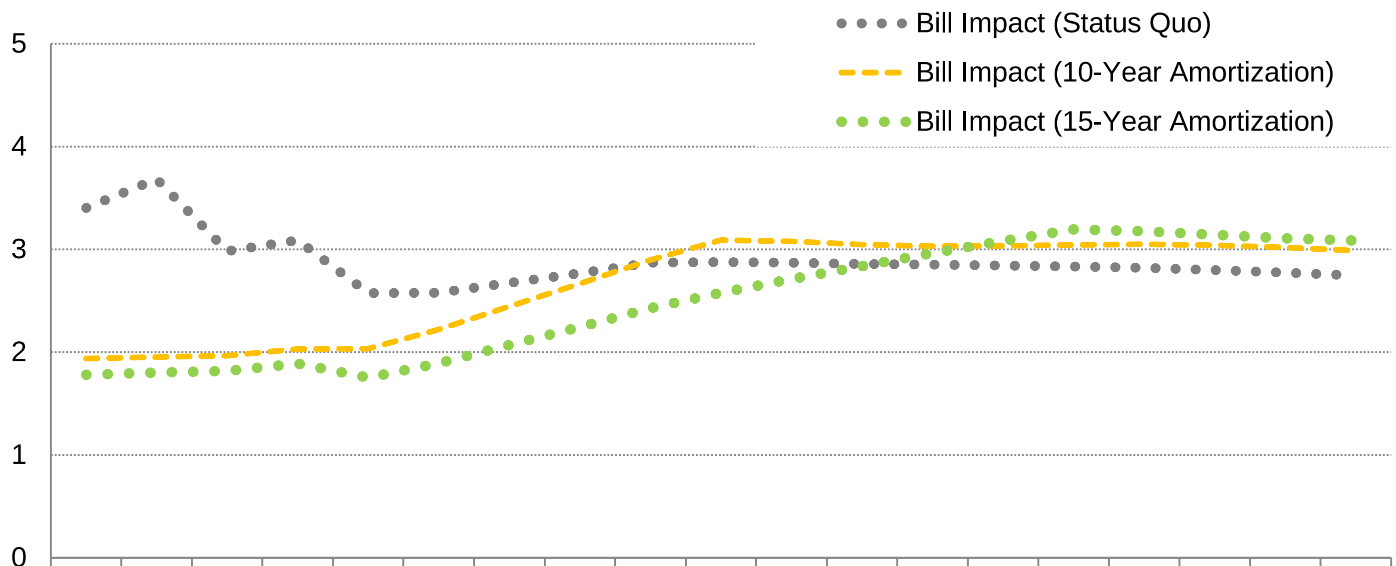
3a. Amortize Conservation Program Costs

- ~$3 billion from the electricity ratepayer base will be spent on conservation programs delivered under the Conservation First Framework (CFF) and the Industrial Accelerator Program (IAP) between 2015 and 2020.
- Currently, Conservation and Demand Management (CDM) program costs are recovered from the Global Adjustment (GA) mechanism about one month after expenses are incurred.
- As a potential rate mitigation measure, certain CDM costs could be amortized. This would involve IESO borrowing funds from the Ontario Financing Authority (OFA) on an annual basis to fund program incentives (non-administrative costs).
  - The time period over which costs could be amortized would be over the lifetime of funded CDM measures.
  - ENERGY is working with IESO to determine the appropriate lifetime period – the graph on the next slide, which illustrates residential bill impacts, presents two cases: **10-year and 15-year measure lifetimes**.
- In both cases, amortizing a portion of conservation spending would produce a benefit for electricity ratepayers in excess of $1/month from 2017 to 2020. Over time the benefit would decrease and turn into a cost (higher electricity rates than would otherwise occur), as interest charges begin to grow. Estimated interest charges are as follows (a 3% interest rate is assumed; increases in interest rates could result in higher overall interest charges):
  - $712 million ($2016) – Amortizing eligible 2017-2035 CDM costs for 10-year period; and
  - $1.3 billion ($2016) – Amortizing eligible 2017-2035 CDM costs for 15-year period .
- Legislative changes would be needed to allow recovery of interest payments from ratepayers, or these costs could be recovered from the Consolidated Revenue Fund (CRF, or taxes).
- An alternative that could be explored would be to pay for CDM costs, or for a portion of these, from the tax-base (*see Appendix for more detail on tax funding option*).

3a. Amortize Conservation Program Costs (cont'd)

Conservation Residential Bill Impact – Status Quo, 10-Year and 15-Year Amortization

CDM Bill Impact ($/month)



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Bill Impact (Status Quo)	3.40	3.68	2.98	3.09	2.58	2.58	2.68	2.77	2.87	2.88	2.87	2.86	2.85	2.84	2.83	2.82	2.80	2.78	2.75
Bill Impact (10-Year Amortization)	1.94	1.95	1.97	2.03	2.04	2.22	2.45	2.67	2.90	3.09	3.08	3.05	3.03	3.04	3.04	3.05	3.04	3.02	2.99
Bill Impact (15-Year Amortization)	1.78	1.80	1.82	1.89	1.75	1.89	2.07	2.25	2.43	2.58	2.71	2.84	2.96	3.08	3.20	3.18	3.14	3.11	3.09

Source: IESO; Ministry of Energy

Note: Chart assumes that conservation incentive costs are available for amortization while administration cost are not. Although there is variable from year to year, incentives represent about two-thirds of conservation spending in Ontario. Chart assumes conservation spending continues at a similar rate beyond 2020. Chart assumes a 10 of 15-year borrowing rate of 3.0%.

3a. Amortize Conservation Program Costs (cont'd)

Considerations

- Under **Public Sector Accounting Board (PSAB) accounting standards**, used by both the Province and IESO, only certain assets can be amortized: 1) pensions and 2) tangible capital assets. Under PSAB an asset must meet several criteria to be considered a capital asset, including:
  - A tangible capital asset must be tangible and substantive and the Ontario government must have title and operate the asset.
  - A tangible capital asset must bring a tangible benefit to the government or to Ontario.
- CDM costs, on their own, do not meet the criteria of a tangible capital asset because customers would have ownership and control of installed CDM measures, not the Province or IESO.
- **Rate-regulated accounting** was developed to recognize the unique nature of regulated entities (e.g., electricity generators, LDCs). Under rate-regulated accounting certain costs can be treated as amortizable assets that would not normally be considered assets under accounting principles.
  - Over the past several years, the Auditor General (AG) has expressed concerns about the appropriateness of recognizing rate-regulated assets in the Province's consolidated financial statements.
  - Rate-regulated accounting is currently under review by international accounting standard setting bodies and is currently permitted only on an interim basis, so its future is unclear at present.

3a. Amortize Conservation Program Costs (cont'd)

Considerations

- If some of Ontario's CDM costs could be amortized, analysis shows that ratepayer impacts would be reduced in the short-term but interest charges on the loan would result in increased overall ratepayer costs in the longer-term.

- Legislative amendments would be needed to allow recovery of loan interest charges from GA.

- ENERGY staff have developed a note to seek an opinion from IESO's external auditor and from the Ontario Provincial Controller (OPC) to determine whether CDM costs could be amortized according to rate-regulated accounting standards.

- ENERGY is working with IESO to seek an opinion on the proposal from IESO's external auditor.

- ENERGY would then send the IESO external auditor's opinion along with ENERGY's explanatory note to the Ontario Provincial Controller (OPC) to seek a formal opinion on whether CDM costs could be amortized according to rate-regulated accounting standards.

- Further legal analysis would also be required to confirm legal viability and possible approaches to implementation.

3b. Rate Smoothing of Conservation Program Costs

- "Rate smoothing" could achieve the same rate reduction effect as amortization.
- Instead of taking out a loan to amortize conservation costs, a regulatory amendment could allow IESO to establish a deferral account for conservation costs.
  - Each year, IESO would defer recovery of a portion of annual conservation costs. Financing would also be required, such as from the OFA, to pay the interest on the deferral account. Interest would accrue on the deferred amounts, likely at the same rates as for the amortization option.
- Deferred costs could be recovered over any time period. If a 10 or 15 year-period was chosen, the rate impacts would be the same as in the amortization option.

Considerations

- Option would **not** require approval of the Provincial Controller. However, choosing this option as an alternative to amortization may open the Ministry to criticism by the Controller and/or Auditor General since the rate impact is the same.
- The Ministry would have more control under this option to change deferred amounts each year, as opposed to the terms set by a loan agreement under the amortization example.
- There is precedence to this approach for nuclear investments, which otherwise would result in volatile increases and decreases for Ontario ratepayers over the investment period. In 2015, the Ministry amended a regulation that requires the Ontario Energy Board (OEB) to set "smoothed" nuclear rates for OPG's Darlington and Pickering nuclear stations over a 20-year period.
  - The regulation allows OPG to defer recovery in rates of a portion of its nuclear revenue during the Darlington refurbishment (expected to be complete in 2026) and recover these deferred costs over the remaining ten years.
  - OPG will establish a "deferral account" to record the deferred amounts each year up to 2026 plus accumulated interest on the balance to reflect OPG's financing costs as a result of rate smoothing. The deferral account is then drawn down on a straight-line basis between 2026 and 2036.
- At minimum, new regulation would be required. However, further analysis is needed to determine the relevant regulation or legislation, to be amended for IESO (e.g., OEB regulation of IESO costs and fees, GA regulation for how IESO recovers its conservation costs from ratepayers).

4. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure

- Fund investments in specific energy infrastructure projects through the tax-base. **Note:** This could include the provincial portion of funding for the Remote First Nation Connection Project, a fund to support projects that improve adequacy and reliability in areas where new transmission would unlock economic growth and expansion of natural gas service to underserved communities.

Considerations

- Tax-base funding would allow for energy infrastructure to be built without impacting electricity and natural gas rates.

Remote Connection Project:

- Ontario ratepayers currently support costs of remote electricity service through RRRP on the order of $28 million/year
- Connecting 21 remote communities to the Ontario grid is supported by a positive business case due to diesel cost savings over time. If RRRP is funded through the tax base as proposed above, this project represents an opportunity to reduce impacts from RRRP.
- Direct investment in Ontario's portion of the capital costs of the project through a provincial fund (e.g., Trillium Trust) could also be considered along with mechanisms for cost recovery through transmission rates to refresh the fund as industry benefits from the transmission investment.
- The amount of investment and long-term savings depend on a federal contribution to the project and ENERGY is currently in discussions with Canada with the goal of concluding a cost-sharing agreement by spring 2017.
- A move to tax-based funding may have implications for cost oversight, since the OEB's mandate is to have oversight of ratepayer impacts. Alternative methods to review cost prudence of tax-based funding may be needed.

4. Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (cont'd)

Considerations (cont'd)

Transmission Projects to Enhance Economic Growth:

- A tax-based fund could target investments in projects that have been identified in IESO regional plans and that would stimulate economic growth but are not proceeding due to cost barriers under the OEB's beneficiary pays principle. Investments could also target areas where the existing system poses challenges for delivering reliable service such as in parts of Northern Ontario with long single circuits.
- Potential opportunities for investment could include a transmission reinforcement in the **Greenstone area**, upgrades south of **Red Lake** and others TBD based on program design.
- This approach would allow a potion of project costs to be socialized to advance key projects without impacting rates or OEB's principles of cost allocation. Scope and scale of fund would be refined through program design.

Natural Gas Expansion to Underserved Communities:

- The Government has currently committed to expanding natural gas access to more communities in Ontario (i.e., $200 million Natural Gas Access Loan and $30 million Natural Gas Economic Development Grant).
  - Natural gas is an affordable heating source in Ontario. Its continues to be less expensive than alternative sources such as electric baseboards, heating oil and propane. For example, switching from oil to natural gas can save an average consumer an estimated $1,500 annually.
  - Increasing access to other energy sources such as natural gas, provides Ontarians with more options to meet their needs, reduce their energy costs and improve their quality of life.
  - Expansion of natural gas delivery infrastructure is widely supported in underserved communities (i.e., a recurring theme at ROMA) as a means to provide consumers and businesses in underserved communities with more affordable energy choices, attract new industry to Ontario and benefit agricultural producers.
- A grant program complements the Ontario Energy Board's recent decision enabling greater rate-based expansion to unserved areas, including rural and remote communities.
  - Applying Trillium Trust funding would make it possible to enhance the Grant Program and service more communities.

5. Dedicate Departure Tax

- In connection with the IPO, as a result of leaving the PILs regime and entering the corporate tax regime, Hydro One was deemed to dispose of its assets for proceeds equal to its fair market value, triggering a PILs liability of $2.6 billion (Departure Tax).
- This was paid to the Ontario Electricity Financial Corporation (OEFC), to be dedicated towards repayment of electricity sector stranded debt.
- The Province could explore repurposing some of those funds to the benefit of ratepayers.
- This may reduce the risk that the Ontario Energy Board (OEB) assigns to ratepayers the benefit from an associated tax asset, resulting in lower earnings and decreased share value for Hydro One. This decision is currently before the OEB, as part of Hydro One's Transmission rate application.
- If the Province were to transfer $2.6 billion in economic benefits to the rate base over 10 years suggest the following impacts (assuming 140TWh per year):
  - Residential Ratepayer Impact (if spread over 10 years): up to $1.39 per month on a typical bill; and
  - Industrial Ratepayer Impact (if spread over 10 years): up to $1.86 / MWh

Considerations

- Cost savings to ratepayers and associated fiscal impacts would depend on timing and which ratepayers (e.g., Hydro One customers, or all Ontario customers) will benefit from some or all of the $2.6 billion value.
- The departure tax was effectively a true-up for lower PILs payments from Hydro One in previous years – it was not a one-time windfall for the Province. In other words, it ensures that Hydro One paid all its tax obligations under the PILs regime before moving into the normal corporate tax regime.
- The related ~$2.4 billion fiscal benefit to the Province (from the deferred tax benefit) has already been credited to the Trillium Trust to be used to build infrastructure under Moving Ontario Forward.
- Repurposing funds paid to OEFC may have an impact on the defeasance of electricity stranded debt.
- While this is a shift from messaging that value from the broadening of ownership of Hydro One is being used pay down debt and fund transit and transportation, the Province could link to electricity infrastructure investments (e.g., as an offset to infrastructure investments already made in the sector, or to specific initiatives such as conservation).

6a. Empower Energy Agencies – IESO / Market Renewal

- Continue to move forward with IESO's Market Renewal initiatives:
  - Market Renewal encompasses projects such as a single-schedule system (from the current two-schedule system), more frequent intertie scheduling to better align with other jurisdictions and a day-ahead market. There will be up front capital costs to enable the initiative. IESO is currently assessing these costs.
  - Moving to "technology-agnostic" procurements will provide new opportunities for innovation and modernization and ensure ratepayers receive the best prices possible.

Considerations

- Changes related to IESO's Market Renewal initiatives, reflected in HOEP and uplifts, are estimated to save up to $300 million per year, starting in 2021, leading to a reduction of:
  - About $1/month or less than 1% at current retail prices for a typical residential bill; and
  - About $1.30/MWh at current all-in prices for industrial and SME electricity consumers.

- The IESO's Market Renewal is a broad initiative that will impact all aspects of Ontario's electricity market. Ontario has had a uniform price since market opening.

- Adopting a technology-agnostic stance will lower the overall cost of providing electricity service by selecting the most cost-effective resources to fulfill various system needs.

- IESO estimates that the total implementation cost – including a 15% contingency and net of avoided costs – will be $150 million. The bulk of the costs (capital) would only be recovered once the project has been implemented and as the benefits are being realized.

6b. LDC Efficiencies and Rates

- Reducing costs and having LDCs become more efficient could result in a reduction of Distribution costs on electricity bills.
  - Currently, LDCs recover costs through the Delivery line of the electricity bill, which is broken into Distribution and Transmission costs. LDCs are responsible for the Distribution costs of the electricity bill which account which account for about 20% of the total bill.
  - Distribution costs vary across the province as LDCs have different service territories and needs (e.g., geography, number of customers, density of customers, life/health of capital assets, etc). See next slide for more detail.
    - For example, comparing 2016 with 2006, distribution rates have increased by about 24.5% (or about 2.2% per year, compounded annually) across the Province, with significant variation between regions and LDCs (-17% to 148%). Overall consumer price inflation in Ontario for the same period increased by about 19% or 1.8% per year.

Considerations

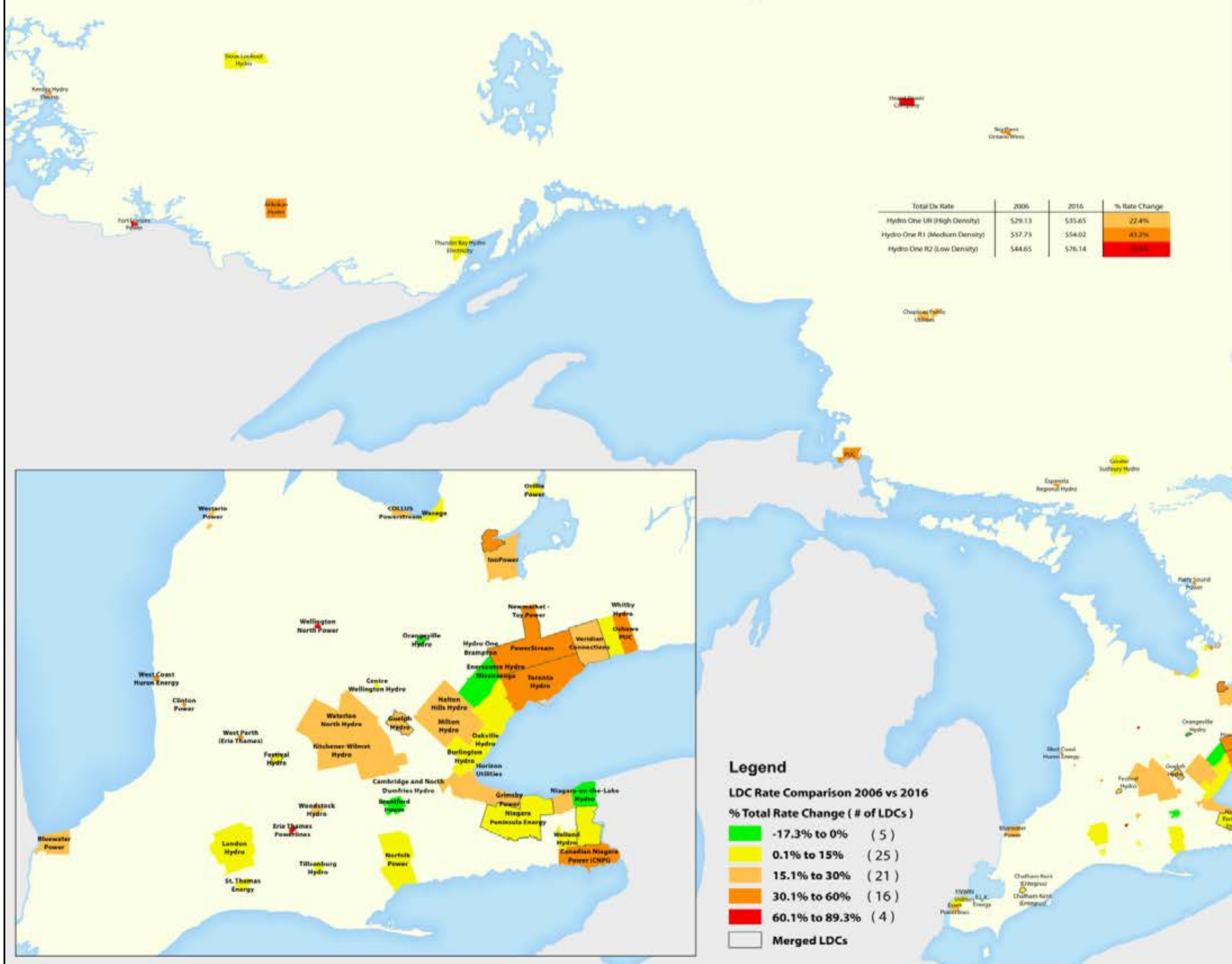
- The Ontario Energy Board (OEB) has a mandate to regulate the electricity distribution sector in the public interest, ensuring the financial viability of the sector while promoting reliable service to customers at just and reasonable rates. Since 2012, the OEB has taken action – through the Renewed Regulatory Framework for Energy – to more closely link rate regulation with performance measures and outcomes.

- There maybe opportunities to promote further cost reductions and performance improvements within the distribution sector as there is continued evolution of the regulatory framework in Ontario.
  - Tightening LDC requirements may also indirectly incent other desired policy outcomes, such as LDC consolidation and grid modernization to realize further cost reductions.
  - To further help address the costs associated with the Delivery line of the electricity bill, program such as the RRRP (previous slide) could be expanded to include other customers that may face higher costs.

- ENERGY could help promote or accelerate these efforts by asking the OEB through the LTEP Implementation Directive, s. 35 of the *Ontario Energy Board Act, 1998*, and the 2017 Mandate Letter and other agency business planning processes.

- In 2012, the government asked the Ontario Distribution Sector Review Panel to review the distribution sector and make recommendations about how it could become more efficient. The Panel concluded that a $1.2 billion net present value in savings could be achieved by consolidating LDCs into 8-12 regional entities. The panel recommended legislation to mandate consolidation.
  - Rather than mandating consolidation, the government response was to pursue voluntary consolidation and put in place tax incentives for consolidation. Further changes to the tax incentives and/or revisiting legislated consolidation could be considered.

LDC Distribution Rate Changes (2006 vs 2016)



Total Dx Rate	2006	2016	% Rate Change
Hydro One UR (High Density)	$29.13	$35.65	22.4%
Hydro One R1 (Medium Density)	$37.73	$54.02	43.2%
Hydro One R2 (Low Density)	$44.65	$76.14	[illegible]

Legend

LDC Rate Comparison 2006 vs 2016

% Total Rate Change (# of LDCs)

- **-17.3% to 0%** (5)
- **0.1% to 15%** (25)
- **15.1% to 30%** (21)
- **30.1% to 60%** (16)
- **60.1% to 89.3%** (4)
- **Merged LDCs**

KEY FINDINGS

- In summary, distribution rates (including rate riders) have increased by about 24.5% across the Province, with significant variation between regions and LDCs (-17% to 148%).
- There is generally no correlation between LDC size or location and distribution rate increase in absolute or percentage terms.
- The current analysis shows no clear relationship between the percentage rate increase and the absolute rate level (that is, high rate increase LDCs may still have among the lowest rates, and low rate increases may have higher rates.
- No clear relationship between amalgamation and rates.
- The analysis does suggest that Hydro One has the highest rates, and some of their customers have seen higher than average rate increases.

NOTES

- **Rate Calculation:** Monthly residential distribution bill rates, before taxes, are based on consumption of 750 kWh. Distribution charges account for approximately 23% of the average 2016 residential bill.
  All figures calculated by ENERGY staff without input from OEB.
- **Colours:** Colour coding of the map only depicts the change in LDC rate amounts (i.e. LDCs in red don't necessarily have the highest total rates).
- **Mergers:** Rates for customers in merged LDCs have experienced different levels of change. For merged entities, the largest LDC in 2006 was used. An accompanying map focuses on merged entities.
- **Points in Time:** Current analysis compares 2016 and 2006 only. Rates could have had an uneven trajectory, especially considering regulatory decisions such as time limited charges/rebates with temporary impacts.

Only LDCs with distribution rates of 2006 and 2016 are shown.
Only the largest distribution areas are shown and smaller satellite areas are not all shown.

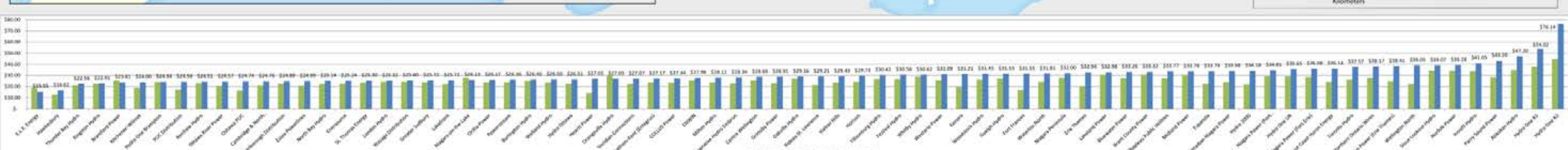
Below LDCs had either acquired or merged: (# of merged LDCs)

a. Powerstream Inc. (5)
b. Chatham-Kent Hydro Inc. (13)
c. Veridian Connections Inc. (4)
d. Guelph Hydro Electric Systems Inc. (2)
e. Festival Hydro Inc. (2)
f. Orangeville Hydro Limited (2)
g. Niagara Peninsula Energy Inc. (3)
h. Peterborough Distribution Incorporated (3)

Data source: Rate database, Rate orders and OEB yearbook
Produced by Strategic Policy and Analytics Branch,
Strategic Network and Agency Policy Division,
Ministry of Energy

0 30 60 120 180 240
Kilometers

Published December 2016



6c. Empower Energy Agencies – OPG / Operational Efficiencies

- Provide expectation that OPG meet more aggressive cost targets, improving efficiency by ~$3/Megawatt hour (MWh).

Considerations

- OPG recently submitted its 2017-19 business plan to the Province for concurrence. That plan includes the following:
  - Enterprise total generating cost increasing from $48/MWh in 2016 to an average of $55/MWh over the plan period.
  - An average residential monthly bill increases of $1.05/month annually from 2017-2021.
- Much of this increase is due to the Darlington refurbishment project, which increases costs and reduces OPG's generation over the planning period.
- OPG has also shared its stretch targets for total cost of generation, which average $52/MWh over the 2017-19 plan, a ~$3/MWh reduction (5-6%) relative to its $55/MWh business plan targets.
- The Province could provide instructions to OPG to focus on its stretch target as part of the Minister's Concurrence letter. This is a public document that OEB would likely review and incorporate as part of OPG's current rate application.
- Consistent with regulations under the *Ontario Energy Board Act*, OPG is seeking smoothed rates for nuclear as part of its 2017-2021 rate application.
  - As a result, the benefit to ratepayers of reducing generation costs is uncertain.
  - Given that the application extends beyond the business plan period, and to ensure OPG does not delay costs beyond the planning horizon, the Province may want to provide additional direction for out year expenditures.
- If OPG is unable to meet more aggressive cost targets, this could impact net income, and the Province's fiscal plan.
  - The total cost of $3/MWh based on OPG's forecast production of 74 TWh/yr is about $240 million per year.
- The Province could work with OPG to craft language in the concurrence letter in order to avoid setting unintended precedents for future rate application processes.

7a. Give Consumers More Rate Choices and Greater Transparency – Interim Flat Rate

- OEB continues to move forward with its Regulated Price Plan (RPP) Roadmap:
  - The OEB is undertaking a comprehensive review of the RPP, including exploring the introduction of offering different pricing plan options for customers following the completion of pilot programs in 2018. The plan is expected to be implemented over a 3-5 year period.
- Until new pricing plans are available, the OEB could provide an "opt-in flat rate RPP" structure that could be made available to residential, farm and small business consumers on an interim basis (2-3 years) until a wider range of price plans are available, providing customers with pricing choice.
- Time-of-Use (TOU) pricing could also be introduced for non-RPP Class B consumers to reduce Global Adjustment (GA) volatility and reduce system costs.

Current TOU	New Flat Rate
On: 18.0 ¢/kWh	11.1 ¢/kWh
Mid: 13.2 ¢/kWh	
Off: 8.7 ¢/kWh	

Considerations

- Would provide consumers with electricity pricing choice.
- The OEB has indicated that the option would lead to no overall change in system costs. Consumers with higher peak and mid-peak usage patterns would see a decrease in their electricity bills, while those with higher off-peak usage patterns would see an increase.
  - While the current strong supply conditions may allow for such an RPP structure (i.e., peak demand requirements can be easily met), administrative costs could be high (distributors would need to design/implement an opt-in process and associated billing system on an interim basis).

	Current TOU	New Flat Rate
1) Monthly electricity bill- higher peak and mid-peak usage patterns	$172	$163
2) Monthly electricity bill- higher off-peak usage patterns	$152	$163

***Note:** 1) assumes a consumer consumption pattern of 45%:30%:25% (Off-peak: Mid-peak: On-peak), while 2) assumes consumer consumption pattern of 80%:10%:10% (Off-peak: Mid-peak: On-peak). Estimates are based on OEB's online electricity bill calculator (for Toronto Hydro- November 2016 rates)

7a. Give Consumers More Rate Choices and Greater Transparency – Interim Flat Rate (cont'd)

Considerations

- The decision to undertake smart meter investments was partly justified on the basis of TOU pricing. If TOU pricing were to be made optional, some stakeholders could question the rationale for smart meter investments.
  - Rationale for offering a flat rate option could focus on providing customers with choice until new pricing plans are rolled out under the RPP roadmap.

- If a flat rate design is introduced, there could be significant consumer opposition to any return to a mandatory TOU.

- After the interim flat rate period, the OEB could offer a wider range of pricing plans to consumers.
  - As part of its RPP review, the OEB will be running pilots with LDCs to assess customer response to alternative time periods and pricing structures.
  - Learnings from these pilots will help inform potential changes to the RPP. Pilots are expected to be in market May 2017 and run for one year.

- Non-RPP Class B electricity consumers currently pay Global Adjustment (GA) on a volumetric basis. Moving them to TOU would provide an incentive to shift consumption to off-peak periods.
  - Consumers, including manufacturers, who are unwilling to shift would face higher costs and likely not be supportive of the changes.
  - The decision to pursue TOU pricing for non-RPP class B consumers will impact proceeds recycling as there is interplay between the two initiatives.

7b. Give Consumers More Rate Choices and Greater Transparency – Detailed Global Adjustment

- Provide electricity consumers greater transparency with respect to electricity generation costs by providing more details regarding the Global Adjustment (e.g., adding a line on hydro bills, quarterly energy reports, etc).

Considerations

- As electricity bills have increased, many consumers have complained about a lack of transparency on the drivers of electricity costs. In particular, consumers and legislative officers have singled out the GA.

- Providing consumers with additional information on the cost components and amounts recovered through the GA would help consumers understand how the different forms of electricity generation in Ontario contribute to consumers costs.

- Providing additional information to consumers on electricity commodity cost drivers without sufficient context or background could simply lead to increased complaints about particular generating technologies that make up large shares of costs (e.g., nuclear).

- Adding a breakout of the amount of GA on residential electricity bills could lead to further confusion due to the existing breakout of multiple time-of-use buckets.

- Alternatively, the existing quarterly Ontario Energy Report, which provides various energy sector data, could be leveraged to show a breakout of quarterly GA costs by fuel type. A link on electricity bills could point to this information.

8. Help Small Business Manage Their Electricity Cost – End DRC Early for Class B Electricity Consumers

- Propose to remove the $0.07/kWh Debt Retirement Charge (DRC) from the bills of commercial/small industrial Class B consumers beginning in 2017, instead of April 1, 2018.
  - **Note:** Class A consumers (e.g., large industrial) would continue to pay DRC until at least April 1, 2018.

Considerations

- For a Class B consumer currently paying about $152/MWh, removing the DRC would represent a savings of about 5%.
  - A 50% reduction in the DRC charge would represent a savings of about 2%.
- Alternatively, the reduction of the DRC could be to $0.035/kWh starting in 2017, to provide relief for cap and trade until proceeds recycling is fully operational.
- Residential consumers have had the DRC removed from bills since January 1, 2016. Taking DRC off commercial and small industrial bills would result in equal treatment for these groups of consumers.
- The savings for commercial and small industrial consumers associated with this proposal would drop to zero in April 2018, since this is the current planned date for removing the DRC from non-residential bills.
- Prior to moving forward with this proposal, additional analysis from Legal Services and the MOF would be needed.

9. Extend Length of Existing Wind / Solar Contracts

- Wind and solar developments are typically contracted through standard offer procurements on 20 year fixed terms at fixed pricing.
- Many of these projects have already reached commercial operation.
- The province could explore options for IESO to negotiate extensions to existing renewable energy contracts, for example, by 10 years, in return for the proponents agreeing to a lower price in the near term.

Considerations

- Projects in commercial operation offer potential for near-term rate reduction whereas projects that have yet to reach commercial operation provide potential to mitigate future rate increases only.
- The attractiveness of this option to contract holders would vary from project to project and would depend on project economics.
- Revised pricing would be subject to negotiation, and associated ratepayer savings would be difficult to forecast accurately.
- The duration of contract renegotiation is difficult to forecast and may not be achievable in the near term.
  - Proponents may have to renegotiate their project financing arrangements, ensure project investors are satisfied with any changes in ROI, and extend land leases.
- Project host communities and Indigenous communities whose traditional territory the projects are sited in may not be interested in these projects extending their operational period ; discussions/consultation may be required in advance of this potential option moving forward.

9. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations (cont'd)

- Should Ontario be successful in negotiating lower prices in the near term, it should be noted that contract holders will be in a strong bargaining position (given their existing fixed-priced contracts), and will likely extract additional value from the negotiations.

- Since the Minister of Energy is not a party, IESO would be required to renegotiate the contracts, which would likely involve a direction or directive to IESO.

- Further analysis is required as to how ENERGY could express its policy intent to have IESO renegotiate the contracts for a reduced rate at a longer term, however it is unlikely that IESO could guarantee the outcome.

- Further analysis is required to ascertain whether there is scope within the existing contracts for IESO to renegotiate their terms in this manner.

- Extending contract terms would also reduce planned flexibility and increase the risk of overpayment as this existing capacity would now be contracted into the 2040s and not the 2030s.

- Extending contract terms may require investments in component replacement and additional operation and maintenance costs that developers would seek to recover under any renegotiated contract.

9. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations (cont'd)

- Ontario has over 4,500 MW of wind in commercial operation, with the vast majority being large scale (>500kW) developments.
  - This includes over 2,700 MW of large FIT 1 and GEIA wind projects representing 47 contracts (average size ~58 MW) and over 1,000 MW of solar projects representing 103 contracts.
- Projects over 500 kW would offer the most savings potential as they represent the majority of installed renewables capacity and are spread across fewer contracts.
- Below are two potential approaches to reducing ratepayer costs in the near term by extending contract terms at reduced prices. An illustrative example of a typical large wind project is used.
- **Example:** 100 MW FIT 1 wind project achieving Commercial Operation in 2014 (i.e., 17 years remaining on initial 20 year contract), assuming a 10 year contract extension negotiated at the LRP I low weighted average wind price of $64.5/MWh;
  - (17 years @ $135/MWh + 10 years @ $64.5/MWh)
  - **Potential Approach 1:** Provide a single new contract price that is the average of the lower extension price and the FIT contract price over the new contract term. The new price would be lower over a longer term.
  - **Illustrative Example:** New contract for 27 years at $129/MWh.
  - New contract price set to allow 10% rate of return over 27 year contract per FIT pricing approach.

100 MW Wind Project	Status Quo	27 Year Contract (remaining term extended for 10 additional years)
Contract Cost (NPV 2017)	$550 million	$582 million
Average Monthly Ratepayer Impact Over First 5 Years	$0.03 savings	
Average Monthly Ratepayer Impact Over Remaining 22 Years	$0.02 increase	
Average Monthly Ratepayer Impact Over Entire 27 Year Contract	$0.01 increase	

9. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations (cont'd)

- **Potential Approach 2:** Offer facilities a revised contract that extends terms and is structured to offer lower pricing in the initial contract years and higher pricing in the later years of the contract.
  - For example, the New contract is $85.9/MWh over the first 5 years and $169/MWh over the remaining 22 years.
    - Price over first 5 years is LRP I weighted average wind price.
    - Price over remaining 22 years is set to allow 10% rate of return over entire 27 year contract per FIT pricing approach.

100 MW Wind Project	Status Quo	27 Year Contract	
		Initial 5 Years	Last 22 Years
Contract Cost (NPV 2017)	$550 million	$632 million	
Monthly Average Ratepayer Impact Over First 5 Years	$0.09 savings		
Monthly Average Ratepayer Impact Over Remaining 22 Years	$0.07 increase		
Monthly Average Ratepayer Impact Over Entire 27 Year Contract	$0.04 increase		

10. Tax Relief for Solar and Wind Contracts

- In 2010 and 2011 Ontario procured large scale projects (>500 kW) through the FIT program at standard offer pricing.

- The FIT program was the centerpiece of the GEA which established the economic and social goals of growing the green economy, including establishing a local renewable energy manufacturing base, supporting the development of green energy jobs, and providing incentives for Indigenous participation.

- To help achieve these economic and social goals, the FIT program offered pricing at above competitive procurement rates, and provided Indigenous and Community participation adders, which resulted in economic benefits to all Ontarians, but resulted in additional costs borne by Ontario's electricity ratepayers.

- Ontario could fund the added cost of some or all of these economic and social incentives by shifting their costs from the rate-base to the tax-base.
    1. The tax-base could fund the portion of FIT pricing that is above the cost of wind and solar generation procured through a competitive process.
    2. The tax base could absorb the cost of the incentives paid to encourage Indigenous and Community participation in FIT.

Considerations

- If applied to projects in commercial operation the benefit to the ratepayer would be immediate.
- Comparing FIT pricing to competitive procurement pricing could provide a reasonable representation of energy procurement without the added cost of economic and social incentives.

10. Tax Relief for Solar and Wind Contracts (cont'd)

1. The tax-base could fund the portion of FIT pricing that is above the cost of wind and solar generation procured through a competitive process.
   - For example, from 2017 onward, the estimated value of the more than 1,800 MW of large wind projects in commercial operation under the FIT 1 program at a price of $135/MWh is approximately $9.4 billion (NPV 2017).
   - The weighted average price for large wind projects over the RES I, II and III competitive procurements was $95.1/MWh.
   - If the competitive RES wind pricing were applied to the 1,800 MW of FIT 1 large wind projects, total program value would be estimated at $6.1 billion (NPV 2017).
   - The $3.3 billion difference could be considered the value of above competitive procurement pricing and could be shifted from the rate-base to the tax-base.
   - This represents estimated average ratepayer savings of $1.50/ month relative to OPO forecasts.
   - The same approach could be considered for solar projects however, prior to LRP I in 2016, Ontario had not procured solar capacity competitively and international cost comparisons are challenging given differences in regional development costs.
   - This example does not include the value of participation price adders available for community and indigenous participation.

10. Tax Relief for Solar and Wind Contracts (cont'd)

2. The tax-base could absorb the cost of the incentives paid to encourage Indigenous and Community participation in FIT 1 solar and wind projects.
   - For example, 17 large FIT 1 wind and solar projects have Indigenous and/or Community participation making them eligible for a price adder in addition to their base contract price.
   - The estimated value of these price adders is approximately $17.1 million (NPV 2017) over the expected remaining term of their contracts.
   - This represents estimated ratepayer savings of approximately $0.01/month relative to OPO forecasts.

FIT 1 and GEIA Wind Projects in Commercial Operation
(source: IESO Active Contracts List, October 31, 2016)

Count	Program	MW	COD
1	FIT 1	0.8	Oct-10
2	FIT 1	18	Jul-15
3	FIT 1	23	Aug-15
4	FIT 1	40	Jan-15
5	FIT 1	10	Sep-14
6	FIT 1	10	Sep-14
7	FIT 1	10	Jun-14
8	FIT 1	99	May-13
9	FIT 1	100	Oct-15
10	FIT 1	4	Sep-12
11	FIT 1	100	Apr-16
12	FIT 1	15	Jun-15
13	FIT 1	18	Mar-12
14	FIT 1	104.4	Nov-13
15	FIT 1	40	Dec-15
16	FIT 1	60	May-14

Count	Program	MW	COD
17	FIT 1	125	Aug-13
18	FIT 1	73.5	Aug-14
19	FIT 1	102	Jan-15
20	FIT 1	9	Jan-12
21	FIT 1	4.1	Dec-15
22	FIT 1	0.5	Oct-13
23	FIT 1	82.8	Nov-11
24	FIT 1	18.45	Sep-16
25	FIT 1	60	Jul-14
26	FIT 1	10	Oct-16
27	FIT 1	6.15	Nov-14
28	FIT 1	2.3	Aug-15
29	FIT 1	10	Feb-16
30	FIT 1	8.2	Nov-14
31	FIT 1	150	Nov-14
32	FIT 1	91.39	Dec-14

Count	Contract	MW	COD
33	FIT 1	25	May-15
34	FIT 1	82.8	Nov-11
35	FIT 1	30	Mar-14
36	FIT 1	17.6	May-16
37	FIT 1	23	Dec-12
38	FIT 1	99	May-13
39	FIT 1	48.6	Dec-11
40	FIT 1	19.44	Aug-15
41	FIT 1	10.8	Mar-12
42	FIT 1	38.88	Sep-15
43	FIT 1	60	Aug-14
44	GEIA	270	Mar-14
45	GEIA	180	Dec-15
46	GEIA	148.6	Dec-14
47	GEIA	270	May-15

Key Outcomes / Next Steps

- The proposed initiatives provide the following opportunities to:
  - Provide a greater focus on vulnerable consumers by funding electricity support programs through the tax-base.
    - Enhance existing and new support programs targeted at the most vulnerable consumers (i.e., OESP and RRRP); and
    - Better harmonize delivery rates across the province.
  - Re-set how energy infrastructure is funded by shifting costs to the tax-base from the rate-base.
  - Provide electricity consumers with greater choices and transparency (e.g., alternative rate plan based on a flat electricity rate, unpacking the Global Adjustment costs, etc);
  - Provide system benefits (e.g., market renewal);
  - Increase cost effectiveness and improve efficiency; and
  - Lower the cost of electricity for all consumers.

- The timing of the impact of these rate mitigation initiatives varies.
  - Immediate and near-term impacts can be achieved by shifting costs to the tax-base or changing how certain costs are recovered from consumers or eliminating certain programs.
  - Over the longer term, changes to the electricity supply mix and achieving efficiencies in the electricity market could yield system savings.

- Pursuing the initiatives would require legislative and/or regulatory amendments and working with the electricity sector agencies, LDCs and other stakeholders to implement the initiatives.

Appendix

A. Rural or Remote Rate Protection (RRRP) – Overview and Enhancements
B. Fund Conservation Programs Through the Tax-Base
C. Eliminate the Industrial Conservation Initiative (ICI)
D. Cancel Large Renewable Procurement I (LRP I)

A. RRRP Overview and Enhancements

- The Delivery line of the electricity bill is composed of Distribution and Transmission Costs. While transmission costs are uniform across the province, LDC costs vary by distributor and account for about 20% of the total bill for the electricity customers.
  - See slide X for a map of delivery rate increases between 2006 and 2016.
- The Rural or Remote Rate Protection (RRRP) framework was put in place in 2001 to help offset the higher costs to distribute electricity to Ontario residents who live in rural or remote locations.
- RRRP is available to: residential Hydro One R2 customers (~350,000 customers), Algoma Power customers (~11,600 customers); H1 remote customers (~3,500 customers).
  - To date, R2 customers receive a fixed amount of $125 million a year distributed amongst the customers. Algoma and Remote customers have RRRP calculated by the OEB each year that fluctuates based on average provincial distribution increases.
- Because the amount had been fixed for over a decade, the Province recently increased funding of the RRRP program for Hydro One R2 customers from $125 million to $240 million. This will be effective as of January 1, 2017, and will bring their delivery charges in line with the next highest charges from Hydro One's R1 customer class.

B. Fund Conservation Programs Through the Tax-Base

- Propose to fund 2017-2020 electricity conservation and demand management program costs* using tax dollars instead of ratepayer dollars.
  - Funds received through the Hydro One Departure Tax could potentially be repurposed towards this.
- Total remaining 2017-2020 electricity conservation program costs are expected to be ~$2.1 billion.
- Post 2020, this option could evolve to funding conservation programs through the Greenhouse Gas Reduction Account.

Considerations

- Electricity conservation programs provide a number of benefits to society, however, Ontario's ratepayers have been covering these costs:
  - Avoiding/deferring future energy infrastructure investments, reducing disruption in communities (e.g., avoiding the need to build new natural gas generation);
  - Environmental benefits (e.g., reduced natural gas peaking generation and GHG emissions); and
  - Social and economic benefits (e.g., job creation and assistance managing electricity bills).
- There is precedence for using tax dollars to fund conservation programs.
  - Between 2007 and 2011, Ontario funded the Home Energy Savings retrofit program using tax dollars.
- Funding conservation programs though the tax-base is expected to result in a benefit of $3.40/month for residential electricity consumers in 2017. This could provide immediate short term relief to consumers while other rate mitigation initiatives are developed (e.g., market renewal, LDC efficiencies).

*** Note:** This includes costs towards the Conservation First Framework, Industrial Accelerator Program, Demand Response and the Conservation Fund)

C. Eliminate the Industrial Conservation Initiative (ICI)

- The cost shift from the Industrial Conservation Initiative (ICI) could be removed from electricity bills by eliminating ICI.
  - The ICI allows large electricity consumers to lower their electricity costs by reducing their demand during peak hours.

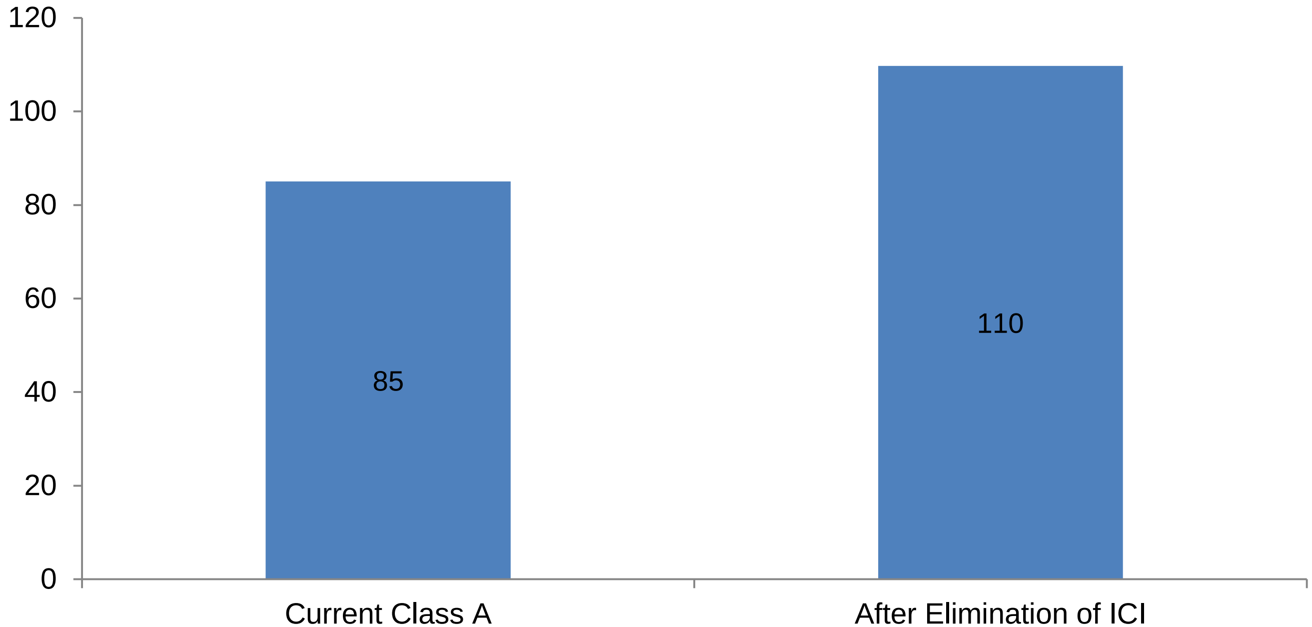
<u>Considerations</u>

- Eliminating ICI would result in a benefit of more than $4/month for residential electricity consumers in 2017.
  - However, unless government took action to mitigate the associated cost shift back to industrial consumers, typical industrial prices would increase by about one-third. Such a price increase would pose significant challenges for energy-intensive consumers.
- Industrial stakeholders have indicated that ICI as an integral factor in maintaining competitiveness and retaining industry in the province.
  - Eliminating ICI would limit the “cost shift” onto residential consumers, but it would also lead to a reduction in industrial demand. The large industrial contribution to the fixed costs of running the electricity system would then need to be covered by remaining consumers.
- If ICI is retained, current IESO projections indicate that the cost shift will decrease each year going forward as Global Adjustment (GA) decreases (due to an expected increase in HOEP).
- Alternatively, ICI could be funded through the tax-base at a cost of $900 million annually. There is precedent to use the tax-base for industrial support programs, including the Northern Industrial Electricity Rate Program (NIERP) and the Jobs and Prosperity Fund.

C. Eliminate the Industrial Conservation Initiative (cont'd)

- ICI currently provides a benefit of about $25/MWh to Class A electricity consumers.

All-In Electricity Price
in $/MWh



Note: Based on year-to-date (YTD) September 2016 prices. Class A reflects a transmission-connected consumer.

D. Cancel/Adjust Renewable Energy Procurements

- The Ministry could consider the following actions to further mitigate future impacts to electricity bills:

Unallocated/Terminated Capacity	Announced Procurements	Executed Contracts
A. Do not procure unallocated or terminated capacity	B. Revise FIT 5 target	D. Cancel LRP I contracts
	C. Cancel FIT 6	

Overarching Considerations

- Cost savings associated with reducing or cancelling renewable energy procurements and programs will not reduce current electricity bills, but would result in future cost reductions relative to Ontario Planning Outlook forecasts.
- The IESO estimates implementing options A to C will reduce system costs by approximately $592 million ($2016) between 2019 and 2028, resulting in an average of approximately $0.50/month in savings to a typical residential electricity bill over the same period.
- The microFIT program is winding down end of 2017. Annual microFIT procurement targets have been undersubscribed.
- With a few exceptions (e.g. rollover of unallocated microFIT capacity; addition of terminated microFIT and small FIT capacity to FIT 5), plans for unallocated or terminated capacity are not defined in announcements or existing directions.

Cancel/Adjust Announced Procurements:

- Amendments to existing directions to IESO would be required to reduce FIT 5 and cancel FIT 6.
- The FIT 5 procurement is underway with a base target of 150 MW and inclusion of any capacity available from contract terminations under prior small FIT and microFIT procurements. The application window closed on November 25, 2016.

D. Cancel/Adjust Renewable Energy Procurements – Existing Contracts

Cancel Existing LRP I Contracts:

- 16 LRP I contracts (approx. 455 MW) have been executed and projects are under development.
- None have met Key Development Milestones. Total value of LRP I estimated at approx. $1 billion (NPV to 2016).

Considerations

- To help inform a decision, IESO or OEB could be asked to evaluate and provide guidance to the Ministry on the system need for LRP I projects and potential ratepayer impacts/benefits.
- 13 of 16 LRP I contracts have Indigenous participation. Cancelling LRP I contracts would remove this economic development opportunity and likely damage relationships between Indigenous communities and the government.
- LRP I Contract includes an “Optional Termination” provision allowing IESO to terminate any contract prior to the “Commercial Operation Date” with 6 months written notice.
- The IESO obligations under the Optional Termination provision depend on whether the project has met all “Key Development Milestones”.
  - As no projects have met their Key Development Milestones, the estimated total cost payable to contract holders is about $8 million.

D. Cancel/Adjust Renewable Energy Procurements – Existing Contracts (cont'd)

Legal Analysis

- Any new directive to cancel LRP I contracts would need to be approved by Cabinet, either as part of an LTEP implementation directive to IESO, or pursuant to the overall power to direct IESO with respect to procurements.
  - An amendment to an existing direction would not require Cabinet approval, however, further analysis is required to determine if direction to cancel LRP I contracts could be considered as amending existing direction.
- ENERGY has previously received advice that there is a high risk that a court would conclude that the Minister has no authority under the *Electricity Act , 1998* to issue a direction requiring IESO to terminate microFIT Conditional Offers and FIT Offer Notices that have already been issued to applicants, because these offers create vested contractual rights. This reasoning would likely apply equally to any direction to IESO to cancel LRP I contracts. Previous advice has also flagged a risk that the Province could be liable for damages in tort for inducing a breach of contract (or other claims).
- The risk and costs associated with potential law suits resulting from the cancellation of contracts requires further analysis. LSB recommends ENERGY seek an opinion from Crown Law Office Civil before proceeding.