MINISTRY OF
ENERGY

# Rate Mitigation Plan Options

## Working Draft

January 2017

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 costs 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) and suspending the LRP II and the EFWSOP (up to $3.8 billion in cost savings).

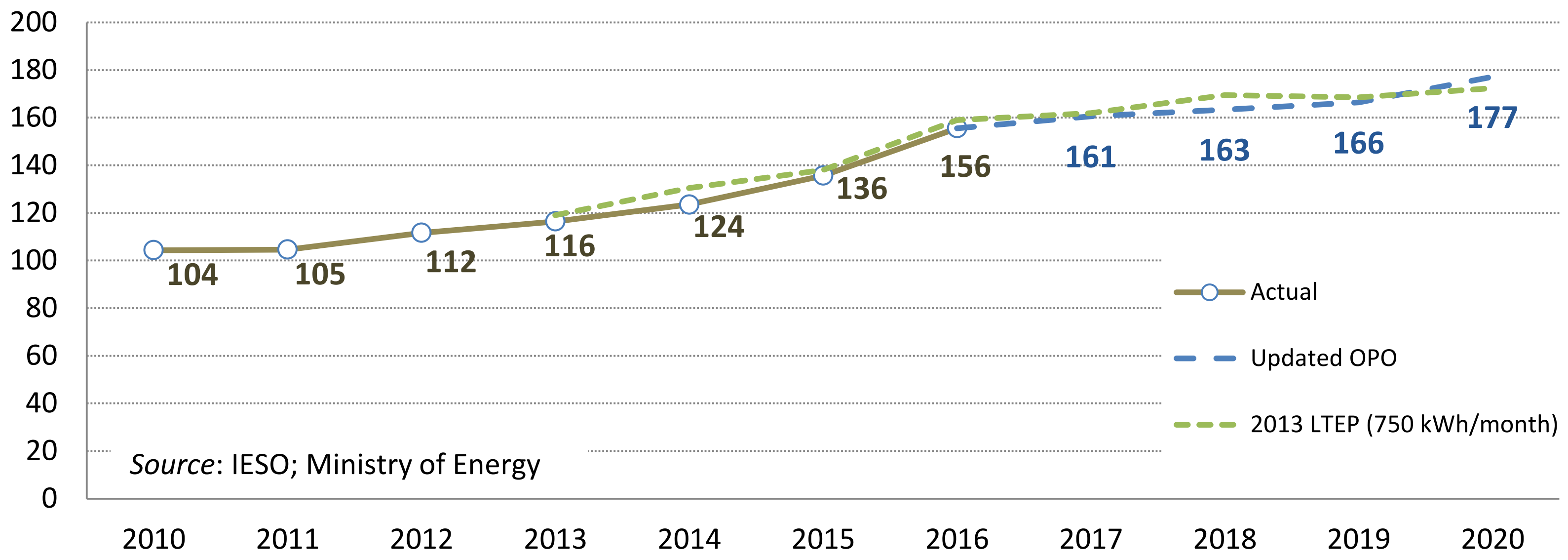
- On November 28, 2016, the Minister of Energy announced the need for changes in how electricity resources are procured, the need for wholesale market renewal and greater electricity consumer choice.

- 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.

# Context – Residential Electricity Prices

- 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 in $/month*

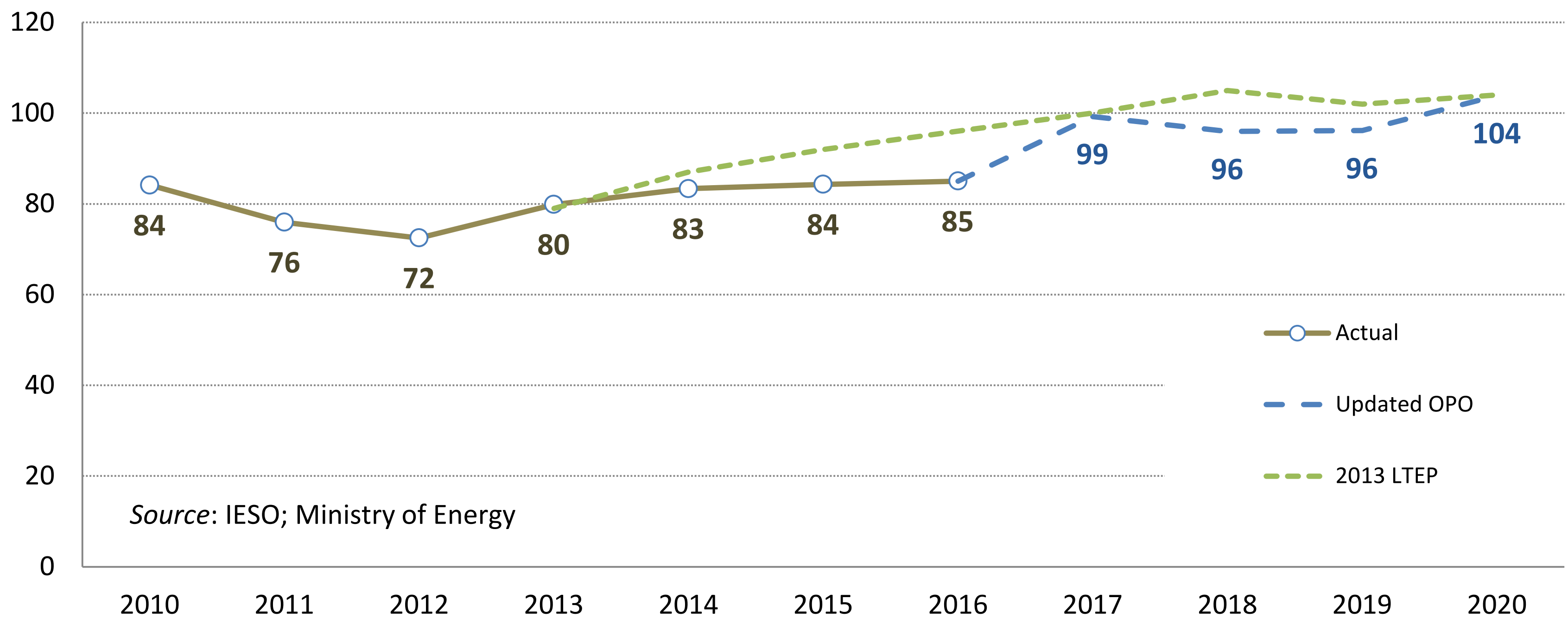



**Note**: The 2013 LTEP forecast for residential bills was based on 800 kWh/month without RRRP or electric heating; the above has been rebased to 750 kWh/month for comparison purposes. Typical residential are based on Toronto Hydro. The updated OPO forecast above includes the 8% rebate to offset the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

# Context – Large Industrial Electricity Prices

- Industrial electricity prices continue to be a concern for many businesses.
  - **Note:** The typical industrial electricity price is currently below the 2013 LTEP forecast.

**Typical Class A Electricity Prices**
*Historical and Forecast in $/MWh*




**Note**: The 2013 LTEP forecast for industrial reflects a transmission connected Class A electricity consumer. The updated OPO forecast above includes ICI expansion and RRRP expansion.

# Broad Policy Themes / Rationale

- In recognition of the costs borne by ratepayers related to the to decarbonizing and modernizing the province's electricity sector:
  1. Provide significant and immediate rate relief through cost deferral of the global adjustment (GA).
  2. Provide a greater focus on vulnerable consumers by funding electricity support programs, such as the Ontario Electricity Support Program (OESP) and the Rural or Remote Electricity Rate Protection, (RRRP) through the tax-base. In addition, provide greater support for lower income Ontarians by enhancing the OESP, etc.
  3. Empower energy agencies to increase cost effectiveness and improve efficiency by having – Independent Electricity System Operator (IESO) modernize Ontario's electricity market through electricity market renewal initiatives, the Ontario Energy Board (OEB) identify opportunities for future LDC cost reductions/efficiencies and work with Ontario Power Generation (OPG) to find further efficiencies in operations and pass on savings to ratepayers.
  4. Enhance the existing 8% rebate that went into effect January 1, 2017.

# Proposed Initiatives – Potential Savings for Typical Residential Electricity Consumers

| *$/750kWh* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Timing of Benefit |
|---|---|---|---|---|---|---|---|---|
| 1. Global Adjustment (GA) Financing (Moderate) | - | 17.49 | 15.01 | 12.49 | 14.91 | 6.32 | 4.03 | Immediate |
| 2. Fund Electricity Support Programs Through the Tax-Base | | | | | | | | |
| a. Rural or Remote Rate Protection (RRRP) | - | 1.58 | 1.62 | 1.66 | 1.70 | 1.75 | 1.79 | Immediate |
| b. Ontario Electricity Support Program (OESP)* | - | 0.83 | 0.83 | 0.83 | 0.83 | 0.83 | 0.83 | Immediate |
| c. Low-Income Conservation | - | - | - | - | - | - | - | |
| d. First Nations Rate | - | - | - | - | - | - | - | |
| 3. Empowering 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 |
| 4. Enhanced Tax-based RPP Rebate (5%) | - | 7.04 | 7.17 | 7.31 | 7.77 | 7.61 | 7.83 | Immediate |

***Note**: Savings based on currently approved OESP rate set by OEB.
**Note:** The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Class B includes small-medium enterprises (SMEs).

# Proposed Initiatives – Potential Savings for Average Industrial Electricity Consumers

| *$/MWh* | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Timing of Benefit |
|---|---|---|---|---|---|---|---|---|
| 1. Global Adjustment (GA) Financing (Moderate) | - | 14.49 | 12.43 | 10.33 | 12.35 | 5.23 | 3.33 | Immediate |
| 2. Fund Electricity Support Programs Through the Tax-Base | | | | | | | | |
| a. RRRP | - | 2.10 | 2.15 | 2.21 | 2.26 | 2.32 | 2.38 | Immediate |
| b. OESP* | - | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | 1.10 | Immediate |
| c. Low-Income Conservation | - | - | - | - | - | - | - | |
| d. First Nations Rate | - | - | - | - | - | - | - | |
| 3. Empowering 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 |
| 4. Enhanced Tax-based RPP Rebate (5%) | - | - | - | - | - | - | - | Immediate |

***Note:** Savings based on current OESP charge as set by OEB.

# Fiscal Impacts

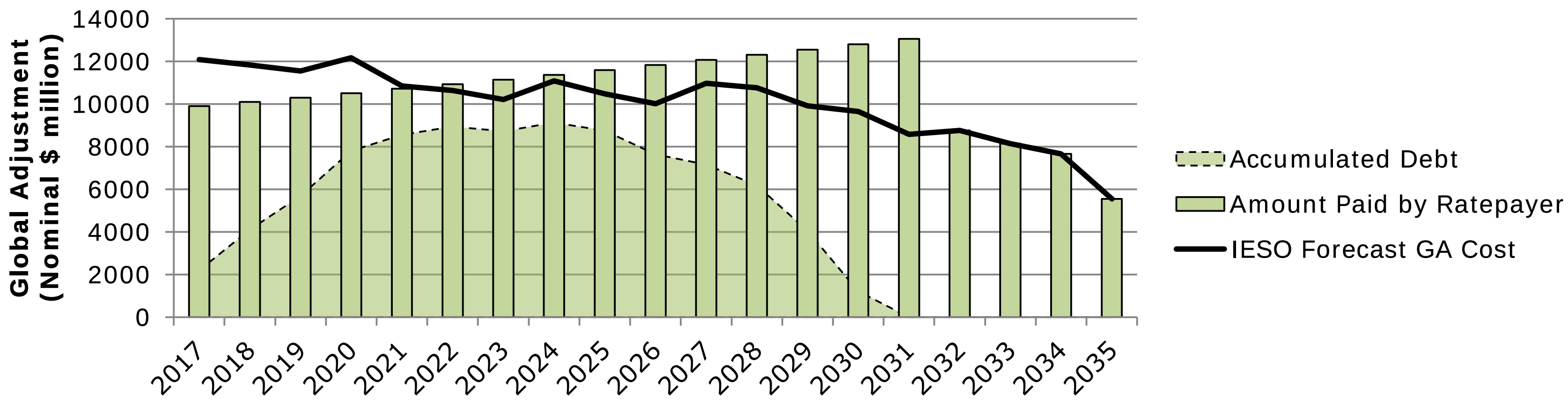
| *$M* | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 |
|---|---|---|---|---|---|
| 1. Global Adjustment (GA) Financing (Moderate) | TBC | TBC | TBC | TBC | TBC |
| 2. Fund Electricity Support Programs Through the Tax-Base* | | | | | |
| a. RRRP | - | $457 | $469 | $479 | $493 |
| b. OESP | - | 162 | 225 | 279 | 323 |
| c. Low-Income Conservation | - | 60 | 60 | 60 | 60 |
| d. First Nations Rate | - | 18 | 18 | 18 | 18 |
| 3. Empowering Energy Agencies To Increase Cost Effectiveness and Improve Efficiency | | | | | |
| a. IESO – Market Renewal | - | - | - | - | - |
| b. OEB – LDC Efficiencies / Rates | - | - | - | - | - |
| c. OPG – Operational Efficiencies** | - | - | - | - | - |
| 4. Enhanced Tax-based RPP Rebate (5%) | 169 | 699 | 679 | 732 | 724 |

***Note:** Includes costs of program expansion and various assumptions as detailed on relevant slides.
**** Note:** Risk to fiscal plan of up to $240 million annually (foregone net income) if OPG is unable to reach more aggressive operational efficiency targets.

**Source:** Ministry of Finance, Energy

# 1. Global Adjustment (GA) Financing

- It is proposed that the amount of global adjustment (GA) paid by ratepayers in each year over the forecast period is set at a fixed amount and money is borrowed to make up the remainder of the GA cost in each year.
- Starting on January 1, 2017, the amount of GA paid by ratepayers is set at a value lower than the true cost of GA in 2017 and is increased according to a pre-defined schedule until the debt has been paid off.
- GA costs will be “smoothed” over time by lowering costs in the short term and increasing costs in the long term.
- In some scenarios, the amount of GA paid by ratepayers *above* the expected actual cost of GA is capped so as to limit large increases in the cost of electricity in any given year.
- All analysis is based on forecasts from Independent Electricity System Operator (IESO), assumes a 5% annual borrowing interest rate and an inflation rate of 2% per year.




**Sample financing**: Ratepayers pay less than the cost of GA in early years, borrowing up to $9 billion that is fully paid off in 2031 by charging ratepayers more than the cost of GA in later years.

# 1. GA Financing – Options

1a. Moderate / GA Financing

- The amount of GA paid by ratepayers in 2017 is lowered by $3.2 and $3.4 billion below the true cost of GA and increases at 2% in each subsequent year until the total amount of money borrowed is paid off in 25 and 30 years respectively.
- Future GA over-payments above the true cost of GA are capped at $2 billion to limit electricity cost increases in any given year.

1b. Moderate / GA Financing with Delayed Increase

- The starting GA payment from all ratepayers in 2017 is lowered by $1.1 billion, ratepayer payments *decrease* in the short term to keep residential bills relatively flat, then increases at 3% each year – up to a maximum of $2 billion above the true cost of GA – until the borrowed money is paid back over a 25 and 30 year financing period respectively.

Low / GA Financing (see in Appendix)

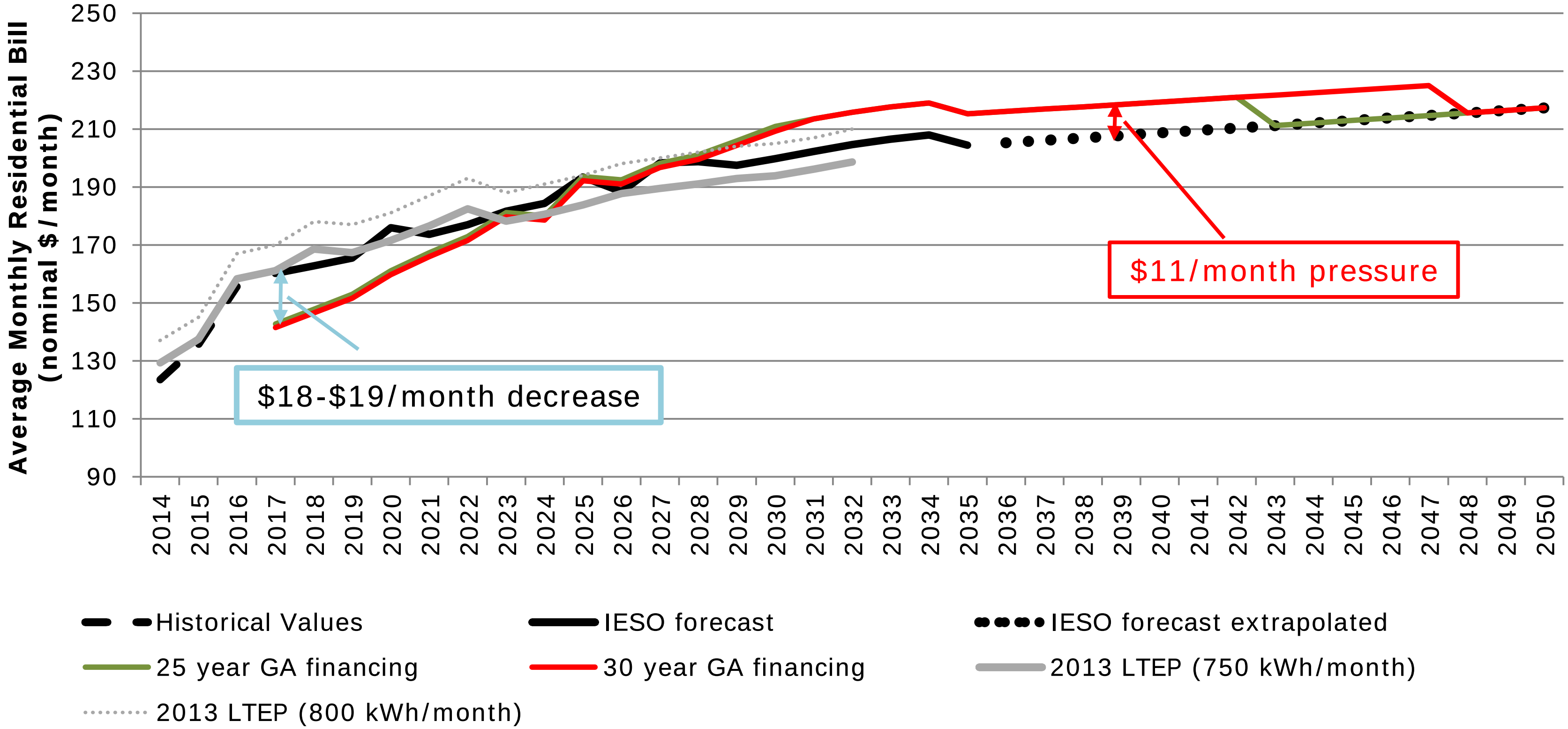
- The amount of GA paid by ratepayers in 2017 is lowered by $2.5 billion below the true cost of GA and increases in each subsequent year until the total amount of money borrowed is paid off.
- Future GA over-payments above the true cost of GA are capped at $2 billion to limit electricity cost increases in any given year.

High / GA Financing (see in Appendix)

- The amount of GA paid by ratepayers in 2017 is lowered by $4.4 and $5 billion below the true cost of GA and increases at 2% in each subsequent year until the total amount of money borrowed is paid off in 25 and 30 years respectively.
- No limit is placed on the amount charged to ratepayers above the true cost of GA.

# 1a. Moderate / GA Financing – Impact on Residential Electricity Bills

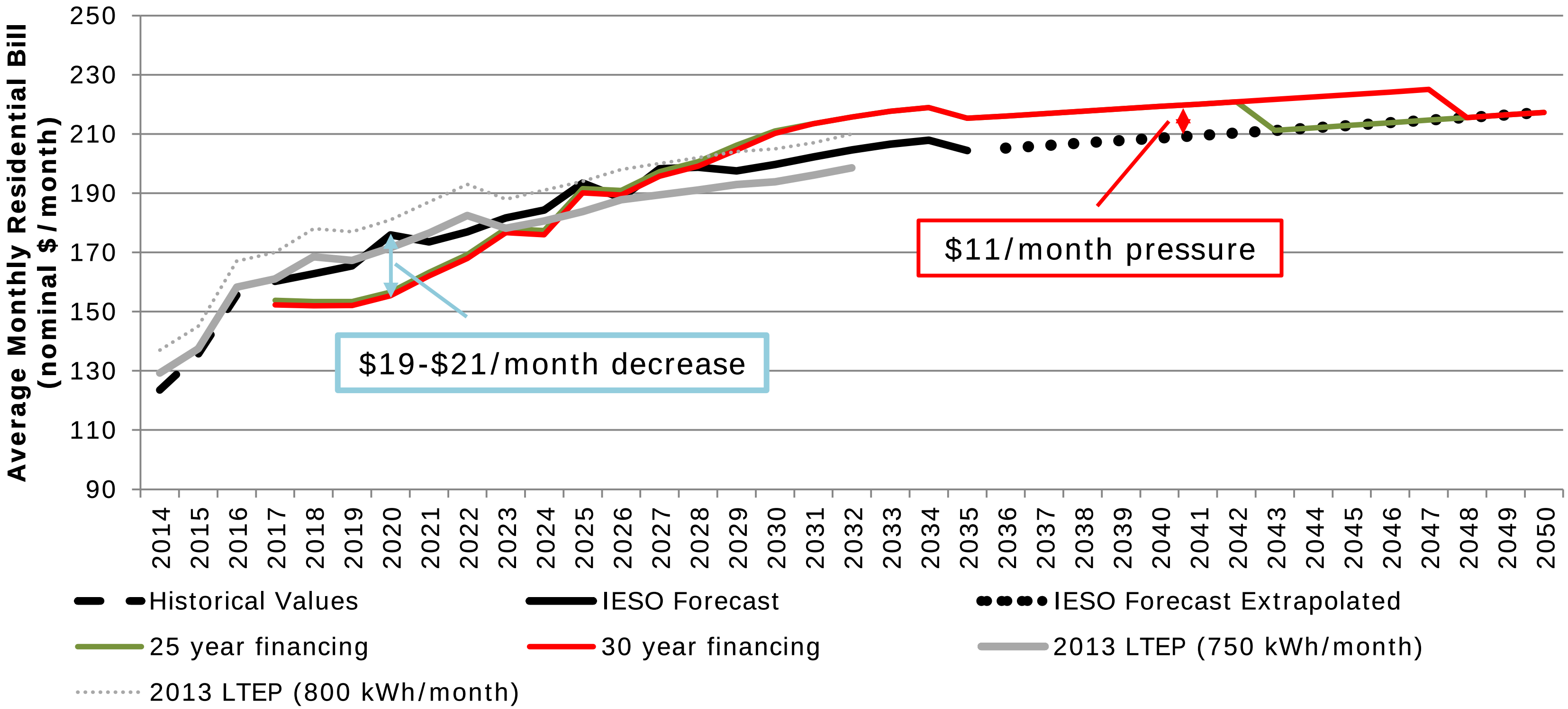
- In this scenario, the starting GA payment from all ratepayers in 2017 is lowered by $3.1 billion (green line) and $3.3 billion (red line) and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 25 and 30 years respectively.




- By **borrowing up to $23 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $17-$19/month** at the cost of **increased future electricity bills over 14-19 years of up to $11/month** above the true cost of electricity production.

# 1b. Moderate / GA Financing with Delayed Increase in Payments – Impact on Residential Electricity Bills

- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $1.1 billion, ratepayer payments *decrease* in the short term to keep residential bills relatively flat, then increases at 3% each year – up to a maximum of $2 billion above the true cost of GA – until the borrowed money is paid back over a 25 and 30 year financing period respectively.

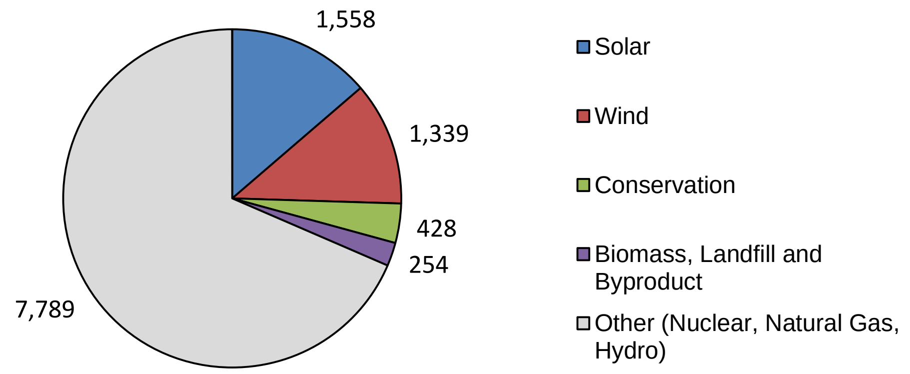



- By **borrowing up to $23 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $19-$21/month** at the cost of **increased future electricity bills over 14-19 years of up to $11/month** above the true cost of electricity production.

# 1. GA Financing – Cost Breakout

- The allocation of GA costs for most of 2016 are as follows:

GA costs year-to-date November 2016 ($ million)




- This cost breakdown will evolve over time as 2,181 MW of contracted generation comes online in the coming years.
- The proportion of GA costs is compared with the proportion of generation in the table below:

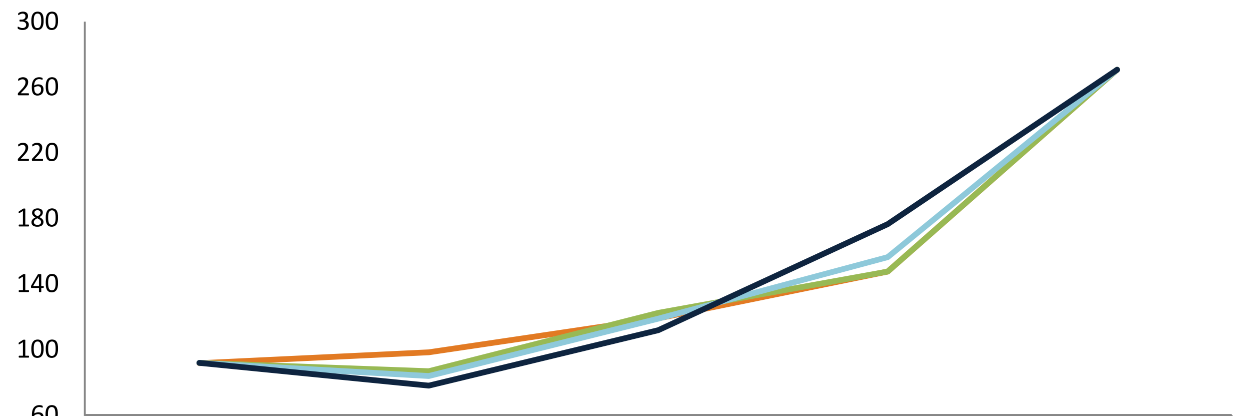
| | Fraction of GA Cost | Fraction of Generation* |
|---|---|---|
| **Solar** | 14% | 0.3% |
| **Wind** | 12% | 6.0% |
| **Biomass, Landfill and Byproduct** | 2% | 0.3% |
| **Conservation** | 4% | 0.0% |
| **Other (Nuclear, Natural Gas, Hydro)** | 69% | 93.4% |

***Note:** Only includes generation directly connected to the transmission system. Most solar generation, for example, is connected to the distribution system and is not represented in the generation column.

# 1. GA Financing – Impact of the Level of Financing on Large Industrial Electricity Consumers

- Below graph illustrates the estimated impact of the level of GA financing for an average Class A electricity consumer over a 25 year amortization period.

**Estimated All-In Electricity Price**
*for Average Class A in $/MWh*




| | 2016 | 2017 | 2027 | 2037 | 2047 |
|---|---|---|---|---|---|
| Status Quo | 92 | 98 | 119 | 148 | 271 |
| Low Financing | - | 87 | 122 | 148 | 271 |
| Moderate Financing | | 84 | 119 | 157 | 271 |
| High Financing | | 78 | 112 | 177 | 271 |

**Note:** Assumes that demand by industrial sector continues at average 2011-2015 levels. Please see the Appendix or more information on the estimated impact on large industrial electricity consumers.

# 1. GA Financing – Considerations

**Considerations**

*Ratepayer:*

- Borrowing money to finance the GA, while lowering costs in the short term, results in a more rapid rise in electricity prices beyond the rate of increase already expected.

- The GA financing proposal involves borrowing large amounts of money over a long period of time (16-30 years, depending on the scenario) to reduce electricity rates. This debt would be highly sensitive to interest rates which could extend repayment timelines or put significant pressure on electricity rates. A long-term interest rate of 5% is assumed for this analysis.

- GA and HOEP provide a natural hedge against each other – when one goes up, the other goes down – keeping total electricity costs relatively stable and predictable. Smoothing only the GA would lead to greater price volatility for consumers unless the schedule and amount of ratepayer payments was defined relative to the actual cost of GA.

- Some Class A consumers pay limited Global Adjustment and would receive little benefit under the financing proposal. These consumers also currently pay very low rates.

- Should Ontario electricity demand be lower than forecasted, the cost of paying off the debt will be spread over a smaller pool of consumption, further increasing future costs for individual ratepayers.

- In recognition that Class B electricity consumers pay the majority of GA costs, could limit GA cost reductions through financing to Class B consumers only.

# 1. GA Financing – Considerations (cont'd)

**Considerations**

*Fiscal / Accounting:*

- Further analysis is required on whether such changes to the financing of the GA would affect the Province's current accounting treatment for the GA and represent a potential fiscal risk. As such, early engagement with Legal Services Branch and Treasury Board Secretariat is advised.
  - It is unclear whether legislation could determine the manner in which this initiative is accounted for. Further work is required.
- Historically electricity sector financing has been conducted by the Ontario Financing Authority (i.e., managing OEFC's stranded debt and borrowing on behalf of IESO). Further consultation with the OFA will be required to determine the appropriate vehicle for additional borrowing.
- The significant amount of additional Provincial borrowing needed to finance the GA, and associated risks (e.g., interest rates, repayment timelines), could put pressure on the Province's credit rating and overall borrowing capacity. Further analysis is required and would suggest early engagement with the OFA through which money will be borrowed.
- The significant deferral of electricity system costs over a long time-horizon and associated interest costs may draw criticism from some stakeholders as creating a new "stranded debt" in the sector. **Note:** the Debt Retirement Charge (DRC) was removed from residential bills in 2016 and will be removed for remaining customers in 2018.

# 1. GA Financing – Guiding Principles (cont'd)

- Based on preliminary discussions with KPMG, the following key steps have been identified:
  - Create an "asset" (and confirm that it meets accounting requirements);
  - Identify who will hold the asset(s), this could include:
    - Province (e.g., OEFC, etc);
    - IESO; or
    - LDCs.
  - Determine the source of the financing (e.g., OFA, IO, etc)

- ENERGY is working with LSB, IESO, MOF, TBS and external accountants to identify legislative, regulatory and accounting requirements associated with GA financing option.

# 1. GA Financing – Considerations (cont'd)

**Considerations**

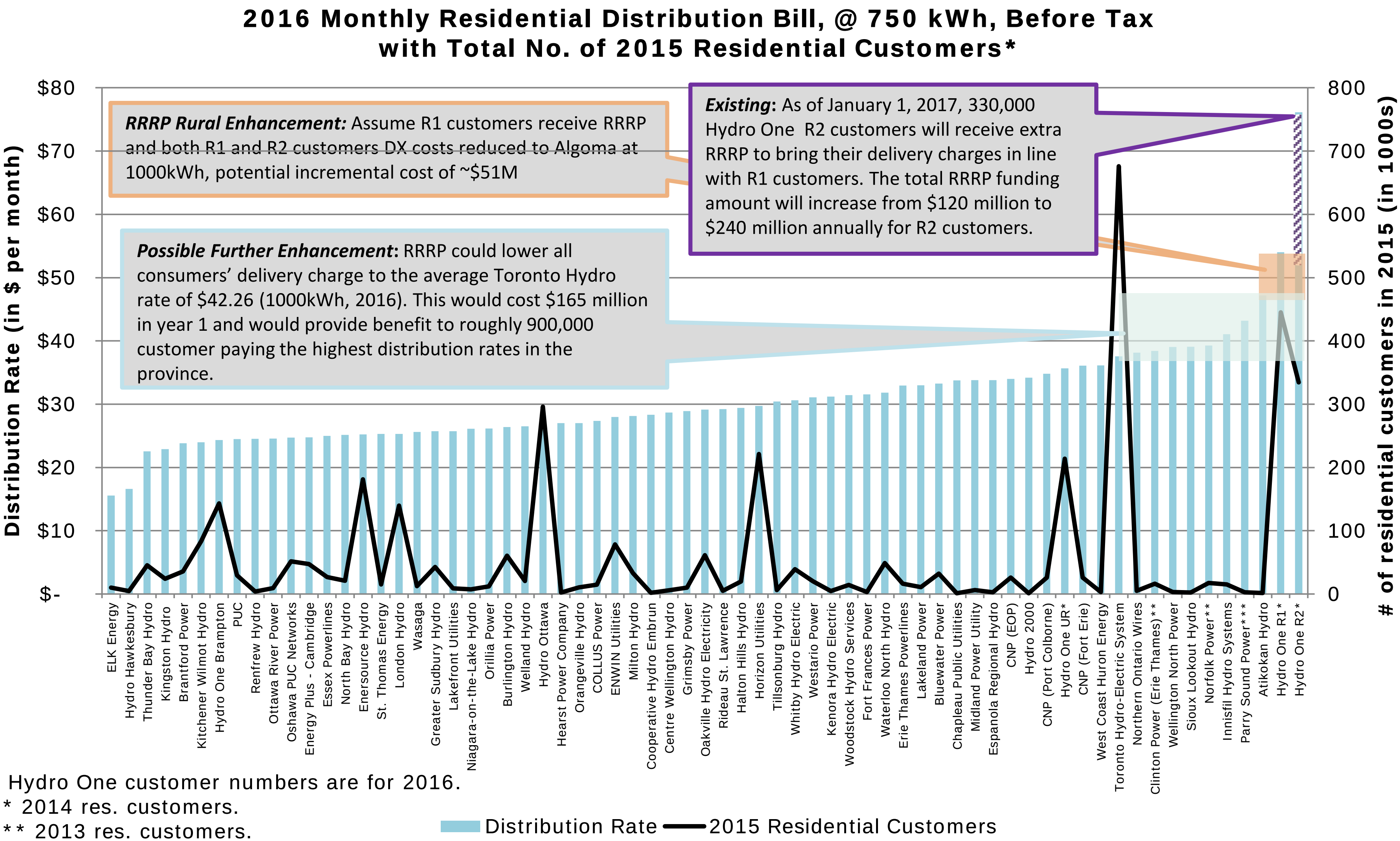
*Legal:*

- Legislation would be required to authorize the financing proposal.
  - Amendments to the *Electricity Act, 1998* (EA) could authorize the financing of certain costs within or part of the GA. However, whether any other legislation requires amendment is not known at this time.
  - The GA regime currently provides that "true costs" represent the true costs of making payments to generators or counter parties to contracts, not the incurring of discretionary financing or interest costs.
  - Considerations such as the need to analyze legal risks or the need to address costs retroactively (if the proposal requires a January 1, 2017 start) could add to the legal and drafting complexity. Further legal analysis is required.

# 2a. Fund Electricity Support Programs Through the Tax-Base – Rural or Remote Rate Protection (RRRP)

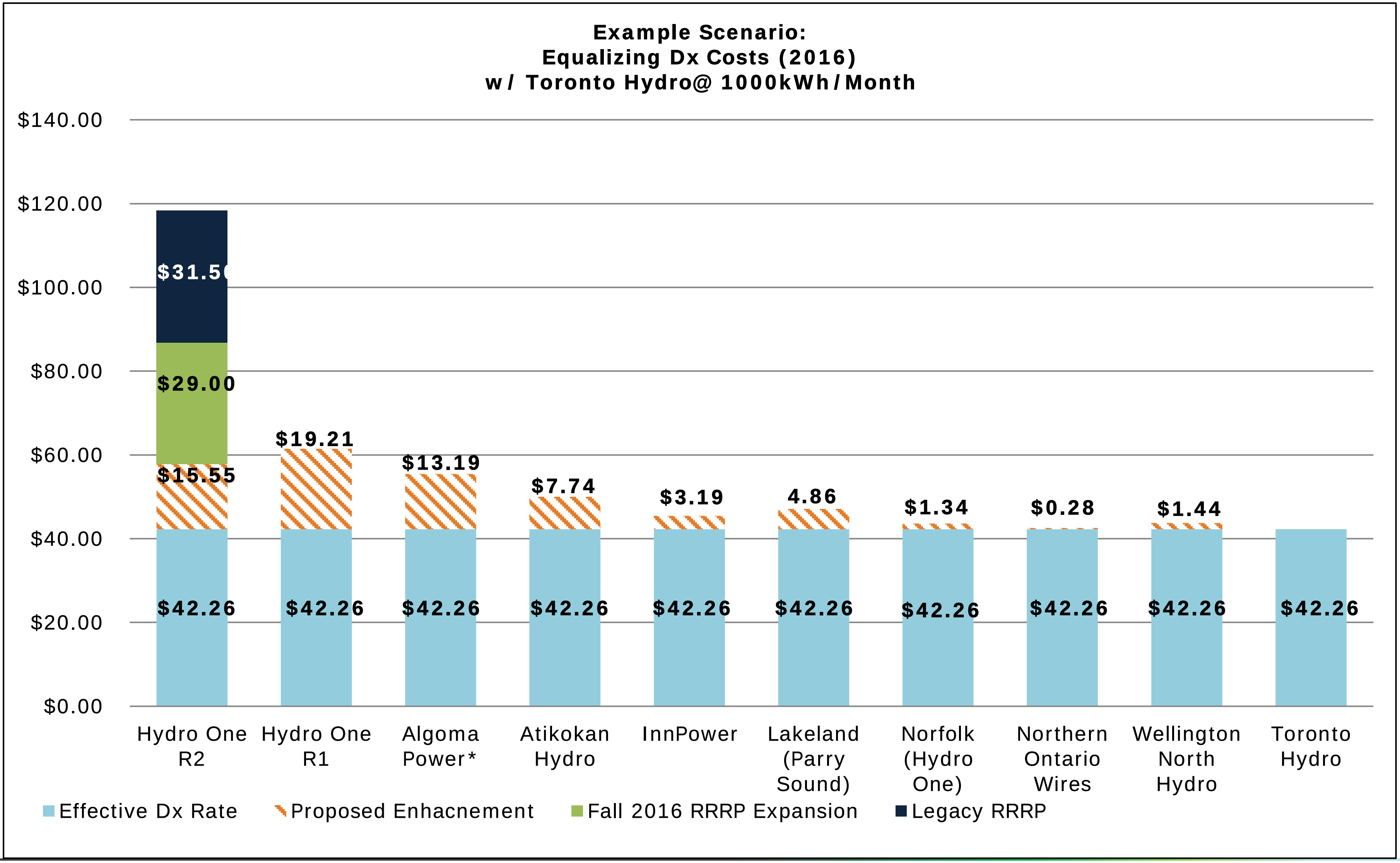
- RRRP supports the most costly-to-serve distributors in Ontario. It is not income tested and most of the support goes to Hydro One's R2 (low density) rate class and remote communities.
- The objective of the program is to reduce extreme distribution costs experienced in low density communities, and bring rates closer to those paid by other customers across the Province.
  - The OEB mandates that low density consumers pay the full cost of service and in recent rate filings has asked Hydro One to ensure this through cost allocation studies. RRRP is thus the mechanism by which these costs can be partly subsidized by all provincial ratepayers.
- Effective January 1, 2017, Ontario has enhanced program funding to further reduce Hydro One R2 distribution rates. As a result, a typical Hydro One R2 customer now pays roughly the same as a Hydro One R1 (medium density) customers, the next highest distribution rate.
- There is opportunity to continue the mitigation of delivery costs for the most costly-to-serve Ontario consumers by revising the program to either:
  - Bring other density based rural costs down by providing benefits to Hydro One R1 customers and ensuring that all RRRP recipients would pay roughly the same delivery costs; or
  - Expanding the program to other distributors that are costly to serve for reasons beyond density (e.g. to bring their distribution rates down to levels currently paid by customers of Toronto Hydro).
- An expansion of the program would result in a cost for all other ratepayers as the RRRP regulatory charge would need to be increased. In order to avoid this and not place an additional burden on consumers, the RRRP program could be transferred to the taxbase.
  - If left on the ratebase, program costs to consumers could rise from an average of $1.58/month to roughly $3.15/month.

# 2a. RRRP Expansion (cont'd)




* Hydro One customer numbers are for 2016.
** 2014 res. customers.
*** 2013 res. customers.

# 2a. RRRP Expansion – Ratepayer Impacts




***Note:** Algoma Power also receives $13.5 million (2017) to support operational costs.

# 2a. RRRP Expansion – Fiscal Impacts

- Table below shows estimate of program costs up to 2022

| Year | RRRP Status Quo($M) | RRRP Enhancement Phase 1 ($M) | RRRP Enhancement Phase 2 ($M) | TOTAL RANGE ($M) |
|---|---|---|---|---|
| 2017 | $292 | $51 | $114 | **$343 - $457** |
| 2018 | $300 | $52 | $117 | **$352 - $469** |
| 2019 | $306 | $54 | $119 | **$360 - $479** |
| 2020 | $315 | $55 | $123 | **$370 - $493** |
| 2021 | $322 | $56 | $127 | **$378 - $505** |
| 2022 | $329 | $58 | $129 | **$387 - $516** |

- Baseline cost of $292M includes all existing funding for Hydro One R2 (including recent $116 million expansion), Hydro One Remotes, and Algoma Power. Providing the enhanced support would cost an additional $165 million (Phase 1 – $51 million + Phase 2 – $114 million) in year 1.

- For forecast purposes, fiscal impacts are escalated at 2.6%/year. This reflects an estimate of the average yearly distribution rate increase.
  - The current RRRP program includes an adjustment mechanism to increase program funding by the same percentage as the average yearly distribution rate increase.
  - The continuation and appropriateness of this mechanism (and in fact all program design characteristics) would be considered in moving the program to the tax base.

# 2a. RRRP Expansion – Considerations

**Considerations**

- **Framework:** New legislation would be required to establish and define the parameters of a tax based RRRP. This may reveal additional considerations.
- **Policy Rationale:** Historically, RRRP has supported costs of LDCs that meet a density threshold. Expanding funding to additional LDCs that do not represent a density threshold (and selecting a specific LDC rate to serve as a cost cap) results in a fundamental change in the program. Program objectives must be considered if expansion is limited to specific LDCs.
- **Program Design:** Program specifics will affect eligible customers, credit amounts, and fiscal impact widely. Issues such as how eligibility is determined and if benefits are equal for all customers within an eligible LDC need to be examined. Financial flow-through mechanisms would need to be considered in consultation with IESO and LDCs. Likely to be modeled after processes used for the Ontario Rebate for Electricity Consumers (OREC).
- **Continuing Support:** There are multiple options and mechanisms available to adjust funding year-over-year depending on desired objective (continuously peg to Toronto, cover annual rate increases, provide inflationary support, amend as needed, etc…). Selection will impact fiscal projections.
- **Fiscal Risk:** As LDC rates change year-over-year, LDCs eligible for tax-based support will change and can cause significant fluctuation in fiscal projects and impacts. For example, if Toronto Hydro meets eligibility criteria in any given year, over 700,000 customers could become newly entitled to taxbase support.
- **Legal Risk:** The OEB is the energy sector's independent regulator and has sole authority to set rates. Ministry-OEB authority must be considered when prescribing cost levels.
- **Hydro One:** Providing tax-based support for Hydro One may be controversial following the broadening of ownership. Hydro One is also transitioning seasonal customers to its R2 and R1 classes; program eligibility will need to be considered.

# 2b. Ontario Electricity Support Program (OESP) Expansion

- 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.
- OESP funding is collected from a charge levied on all electricity ratepayers. Based on current level of program up-take and funding collection, OESP program benefits could be increased across the board by 50%. This would mean:
  - Single low income consumers would see an increase from $30 to $45/ month ($540/year);
  - Families of four with electric heat could see an increase from $55 to $82.50/month ($990/year); and
  - Indigenous and Métis consumers would also see benefit increases at the same level as those with electric heat and medical devices.
    - The Ministry is also considering options to support a “Delivery” line credit for Indigenous consumers. This would cost ~$18 million/year (Option 2d on slide 8) and would save Indigenous consumers between $75 and $100/month.
- Greater focus and support can be placed on lower income Ontarians by funding OESP through the tax base. This would also reduce costs for all consumers as a result of eliminating the OESP charge.
  - Average residential customer savings: $0.83/month; and
  - Average industrial customer savings: $1.10/MWh.

# 2b. OESP Expansion – Fiscal Impacts

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

| Year | OESP Status Quo($M) | +50%($M) | TOTAL ($M) |
|---|---|---|---|
| 2017 | $108 | $54 | **$162** |
| 2018 | $150 | $75 | **$225** |
| 2019 | $186 | $93 | **$279** |
| 2020 | $215 | $108 | **$323** |
| 2021 | $243 | $122 | **$365** |
| 2022 | $272 | $136 | **$408** |

- 2017 program costs are based at current program sign-up rate – 30% of eligible consumers. Cost projections assume the program grows to 100% of eligible consumers by 2022 and remains at that level.
- At the time of program design, it was estimated that 40-50% participation would be high for an application-based program delivered through electricity bills. However OESP can be 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).
- OEB is currently exploring options for simplifying the OESP process, including exploring options with MCSS on auto-enrollment options, discussing options to eliminate wet signature consent forms with the federal government, and working with partners to do open houses to better reach vulnerable consumers.

# 2b. OESP Expansion – Considerations

- **Framework:** New legislation would be required to establish and define the parameters of a tax-based OESP. This may reveal additional considerations, including possible assessment as a tax credit.
- **Implementation:** Financial flow-through mechanisms would need to be considered in consultation with IESO and LDCs. Likely to be modeled after processes used for the Ontario Rebate for Electricity Consumers (OREC).
- **Alternative Delivery:** 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, and could expand coverage to the ~142,000 low-income households that do not receive an electricity bill.
- **Transition to Social Assistance:** Moving OESP to the taxbase can be a transitional step in folding this program into a reform of social and disability assistance programs and enhancement of MCSS' Social Assistance Management System moving forward.
- **Additional Enhancements:** The enhanced credit could 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 and/or R1 customers (highest distribution rates) who are already OESP eligible with the enhanced credit.
- **Variance Account:** The OEB has been collecting program funding in excess of program costs and has accrued a positive balance. This balance must be addressed when moving to the tax base.

# 2c. Low Income Conservation Benefit Program

- Existing low income programs delivered by LDCs and IESO help qualified homeowners and social and/or assisted housing providers improve the energy efficiency of their homes.
  - Programs include the Home Assistance Program and the Retrofit Program (Social Housing Stream).
- A new Low Income Conservation Benefit Program would build on existing programs.
  - Participants could receive incentives for conservation measures not currently covered (e.g. air conditioning, heat pumps (electric heated homes)).
  - Increased incentive amounts (e.g., under the existing Retrofit Program, incentives cover approx. 60% of the total cost of the energy efficiency upgrade).
  - Targeted education and awareness initiatives.
- The new program would be delivered through LDCs and/or IESO.
- The new program would coordinate with CCAP initiatives.
- The budget estimate below is illustrative and assumes annual program budgets three times the 2015 spending for the Home Assistance Program.

| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 |
|---|---|---|---|---|---|---|
| Proposed Budget ($ Million) | $60 | $60 | $60 | $60 | $60 | $60 |

- Further analysis is required on costing and implementation details, including alignment with the Conservation First Framework.

# 3a. IESO – Market Renewal

- Continue to move forward with Independent Electricity System Operator's (IESO) 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.

# 3b. OEB – 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.
- Over the same time period, distribution sector productivity and cost efficiency have decreased. This trend raises concern that customers are not realizing a net benefit from sector cost increases, as customers receive less value from the distribution portion of their bill.
  - OM&A costs per customer have increased on average from $235 in 2006 to $319 in 2015.
  - For the period 2002-2012, sector productivity has decreased by an annual average of -0.93% when including Hydro One and Toronto Hydro, the worst performers.
- 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 incentive for consolidation \further changes to the tax incentives and/or revisiting legislated consolidation could be considered.
- 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.
- 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/or the 2017 Mandate Letter and other agency business planning processes – to consider opportunities to further drive these efficiency, productivity, and performance improvements.

# 3b. OEB – LDC Efficiencies and Rates – Potential LDC Cost Reduction Measures (cont'd)

| Option | Description | Potential Cost Impacts* | Timeline** | Notes |
|---|---|---|---|---|
| **Performance Standards with Rewards & Penalties** | Strengthen LDC scorecard by connecting to LDC financial performance through earnings sharing or penalties paid to consumers.<br>Ex: SAIDI/SAIFI; OM&A per customer | • 1-2% of revenue requirement could be recycled back to customers.<br>• Performance penalties would be real, periodic on-bill $ reductions.<br>• Cost reduction would only occur if standards are not met. | 1 year | UK Regulator Ofgem requires utilities to pay consumers up to £50 if reliability standards are not met. |
| **Enhanced Economic Regulation** | Revise rate-setting to reflect tightening productivity requirements and capital cost avoidance. | • <1% reduction in rates annually, with additional capital investment avoidance.<br>• Methods include stronger productivity factors, broader peer comparisons, and elimination of ICM. | 1-3 years | Incents innovation by requiring LDCs to provide equal or better service on less inflation-adjusted revenue annually. |
| **LDC Collaboration Incentives** | Create regulatory incentives for LDCs to pursue efficiencies and service sharing agreements. | • Potential to avoid individual LDC capital investments of up to six figures, plus additional OM&A tightening.<br>• Actual level of rate reduction dependent on specific LDC proposals. | 1 year for new guidelines, savings to be realized through LDC planning process. | LDCs have already indicated an interest in pursuing such arrangements but have expressed concern on regulatory barriers and costs. |
| **Line Loss Accountability** | Create appropriate benefit-sharing mechanism so LDCs are incented to pursue line loss reductions. | • Potential for 1-3% reduction in commodity charges associated with losses.<br>• Requirements dependent on business cases so costs don't outweigh benefits. | 1-2 years | Potential linkages with related proposal for in-front of the meter conservation. |

***Note:** Dependent on implementation specifics as determined by OEB

****Note:** Timelines begin from Ministry approval of OEB LTEP Implementation Plan

# 3b. OEB – LDC Efficiencies and Rates – Considerations

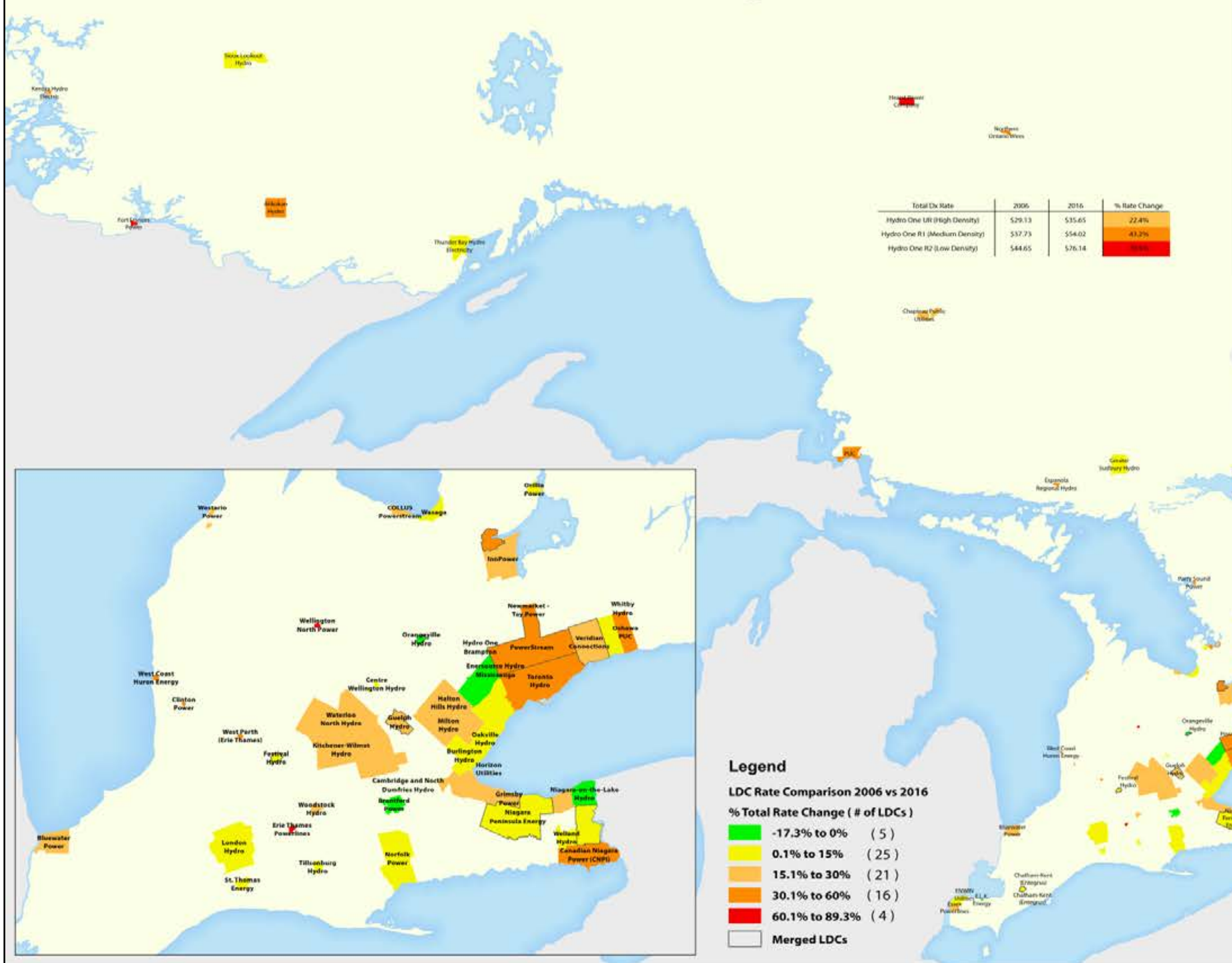
***Sector:***

- Exact bill reduction levels are unknown, but real OM&A and some capital cost avoidance can reasonably be expected.
- Could indirectly incent consolidation if LDCs feel they are unable to adequately manage their assets in light of tightening requirements.
- Any initiatives that have a direct impact on LDC profitability could affect the value of Hydro One.
- There is a tension between requiring productivity enhancements and creating firm performance standards. LDCs have to invest to maintain system levels, but also finding cost efficiencies, which is an incentive for innovation. The Ministry and the OEB may have to also explore reducing regulatory burden/barriers on LDCs so they have the tools available to satisfy new performance expectations.

***Regulatory:***

- The OEB is the electricity distribution sector's independent regulator and as such is responsible for establishing rate-setting mechanisms in line with its statutory objectives.
  - The Ministry would engage with OEB to align on approach, and provide only high-level direction so as to respect OEB's role in determining implementation specifics.
  - The OEB would likely need to conduct policy hearings and stakeholder consultations on these initiatives, though Ministry could request new rules be in place for next major LDC rate cycle.
- LDCs are resistant to peer comparison for a variety of historical and service territory issues. OEB econometric analysis has generally supported limiting peer comparisons. As comparisons would be an important component of benchmarking performance standards, the Ministry may experience sector pushback.
- Updating rate-setting mechanisms and regulatory processes could create regulatory uncertainty and limit LDC activity. The OEB has revised its processes multiple times over the past 15 years.

# 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] |

## 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.

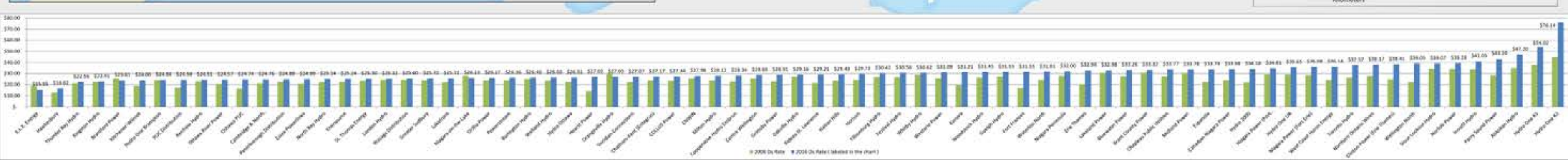
*Only LDCs with distribution rates of 2006 and 2016 are shown.*
*Only the largest distribution areas are shown and smaller satellite areas are not all shown.*

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*

*Published December 2016*



# 3c. OPG – Operational Efficiencies

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

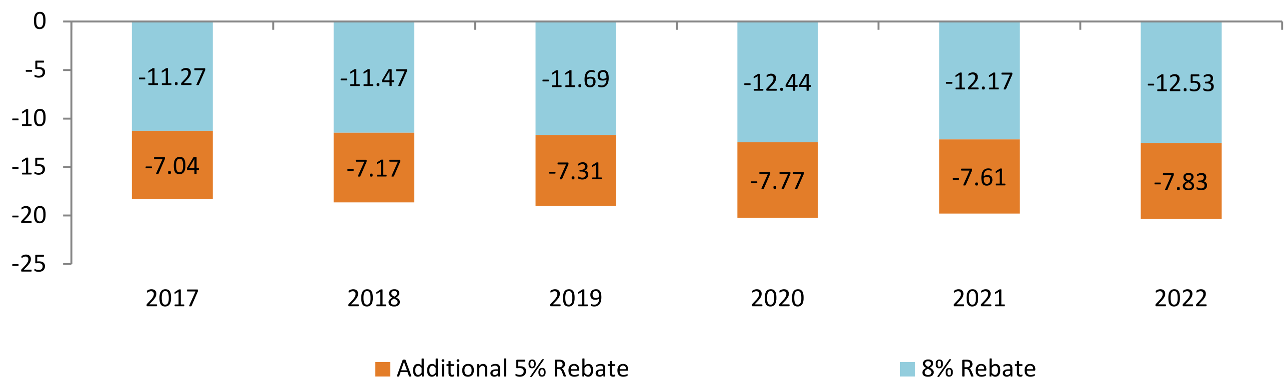
**Considerations**

- 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.

# 4. Enhanced Tax-Base RPP Rebate (5%)

- Enhancing the rebate by a further 5% on the amount before tax provides an average savings of about $7 each month or $84 annually for a typical residential electricity consumer.
- As of January 1, 2017, electricity consumers eligible for the Regulated Price Plan (RPP) receive an 8% rebate equivalent to the provincial portion of HST on their pre-tax bill.
- The eligibility criteria for the 8% rebate is as follows:
  - Consumers with a demand of 50 kW or less;
  - Consumers with a demand of 250,000 kWh/year or less;
  - Farms;
  - Multi-unit residential buildings and other facilities used as residential rental units;
  - Dwellings;
  - Condominiums; and
  - Co-operatives with housing units.

**Benefit for a Typical Residential RPP Consumer**
*in $/750-kWh month*



# 4. Enhanced Tax-Base RPP Rebate (5%) (cont'd)

**Considerations**

- Amendments would be required related to the *Ontario Rebate for Electricity Consumers Act, 2016.*
- The Act authorizes the making of regulations to reimburse electricity vendors for amounts credited to consumers' accounts under the Act. The Act authorizes the making of other regulations to put in place mechanisms needed to implement the financial assistance.
- The rebate could be made retroactive to January 1, 2017. Similar to the current 8% rebate, electricity consumers would receive a retroactive payment once the local distributor begins issuing the rebates if the distributor needs more time to adjust its billing systems.

**Fiscal Cost of an Enhanced Rebate**
*in $millions*

| Cost ($M) | 2016-2017 | 2017-2018 | 2018-2019 | 2019-2020 | 2020-2021 | 2021-2022 |
|---|---|---|---|---|---|---|
| **Cost of 8% rebate** | 271 | 1,119 | 1,086 | 1,171 | 1,159 | 1,208 |
| **Cost of 13% rebate** | 440 | 1,818 | 1,764 | 1,903 | 1,884 | 1,963 |
| **Cost of incremental 5% rebate** | 169 | 699 | 679 | 732 | 724 | 755 |

# Appendix

# 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 ailed 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 area 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.

# Global Adjustment (GA) Financing

- The global adjustment (GA) is comprised of costs for regulated and contracted generation, as well as conservation.

- Some contracted generation assets are expected to have a useful life that extends beyond the term of their current financial contracts (typically 20-years).

- Similarly, conservation costs are recovered through the GA on an annual basis while conservation initiatives provide benefits to the electricity system over the course of many years.

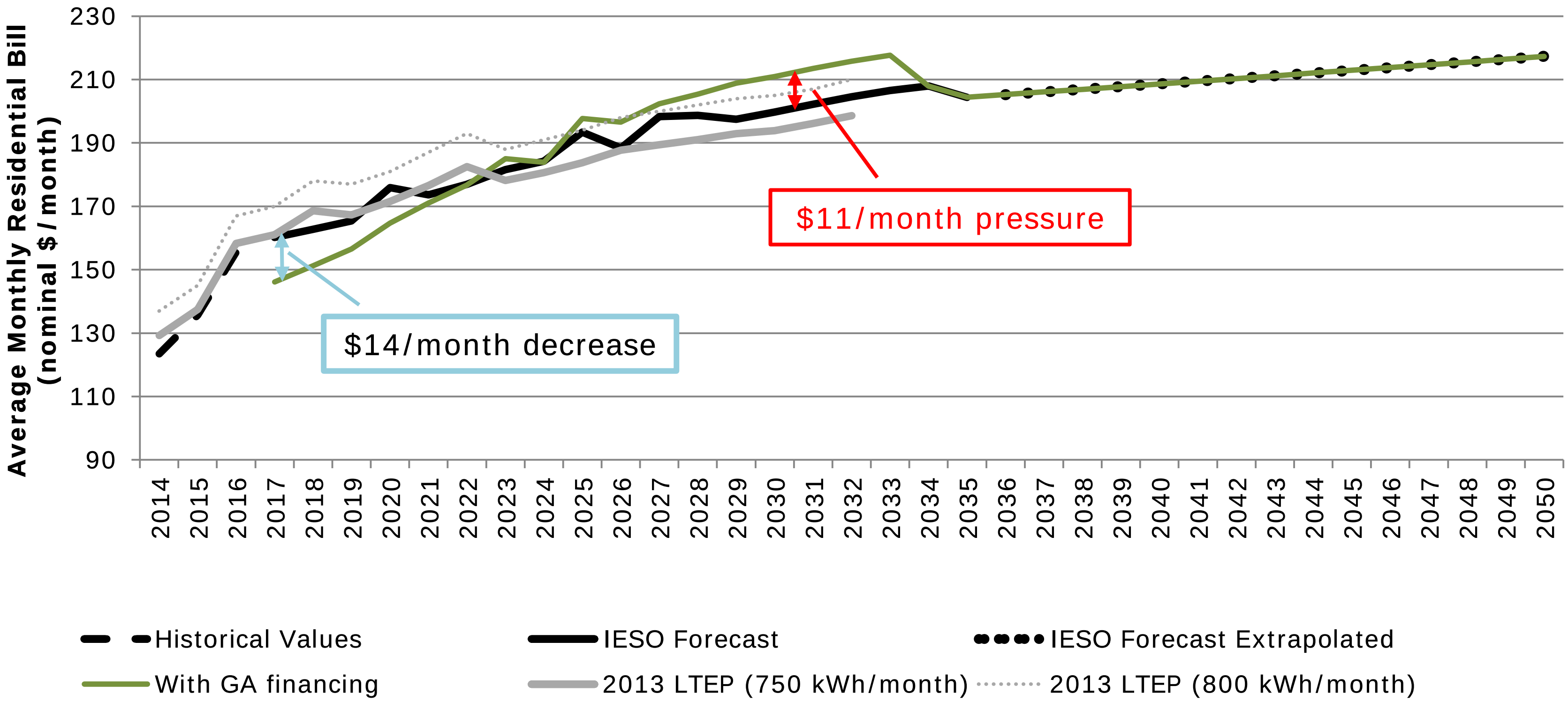
- Since the GA only includes costs related to the contractual life of these assets, there may be an opportunity to recognize the longer-term benefit of these assets to the electricity system and "bring forward" that benefit for ratepayers today, while deferring some of the current costs.

- An indicative GA financing proposal is presented that lowers ratepayers costs over the short term by borrowing money but increases costs over the long term when GA costs are forecast to be lower.

- **Note:** Not all generating assets will continue operations at the end of their contract term. Regulatory constraints (i.e., nuclear licences) or low demand conditions (i.e., as experienced with current expiring NUGs) would mean that some generators will shutdown at the expiry of their contract. Future ratepayers would be paying for these assets that are no longer producing power.

# Low / GA Financing – Impact on Residential Electricity Bills

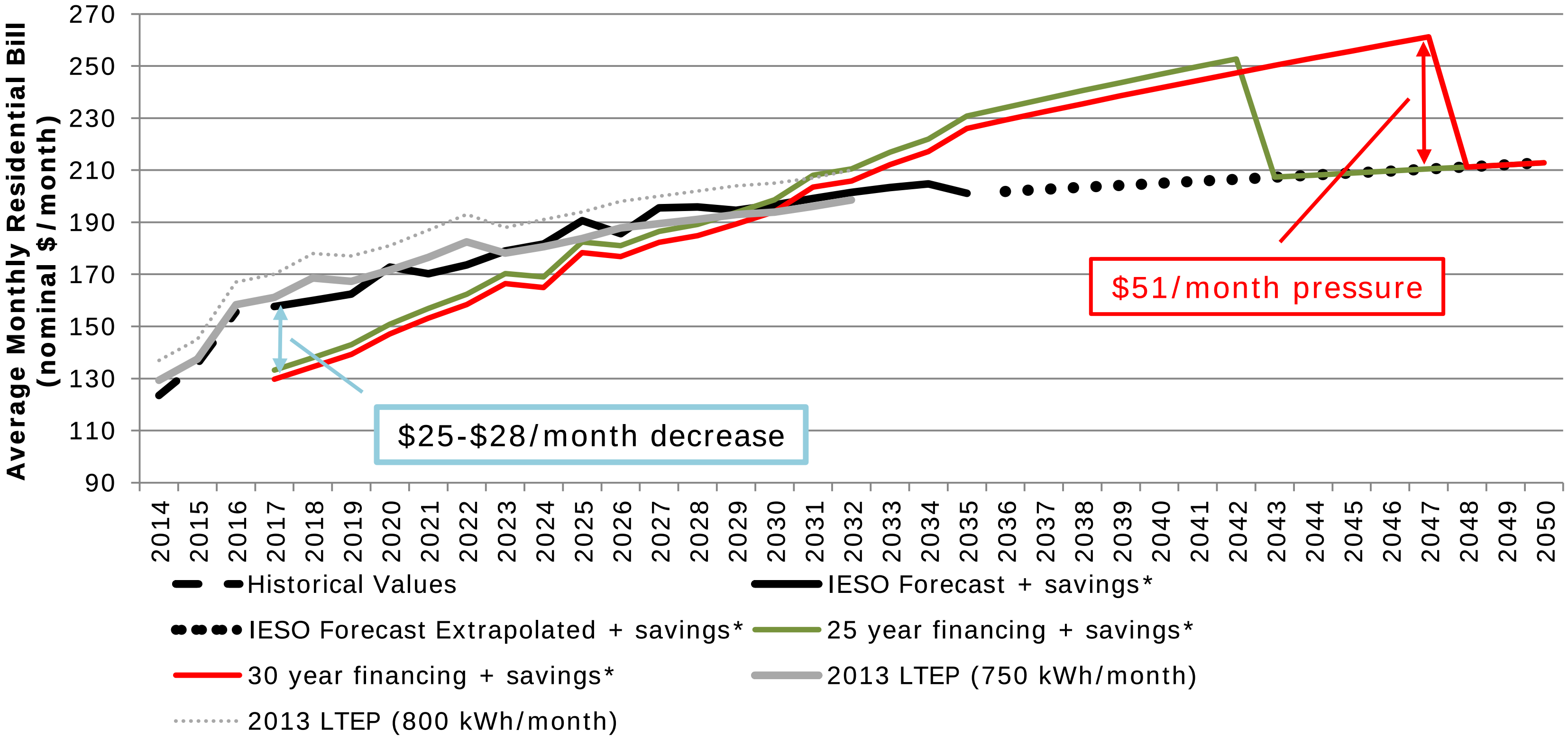
- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $2.5 billion and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 2032.




- By **borrowing up to $9.3 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $14/month** at the cost of **increased future electricity bills over 10 years of up to $11/month** above the true cost of electricity production.

# High / GA Financing – Impact on Residential Electricity Bills

- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $4.4 and $5 billion and increases at 2% each year until the borrowed money is paid back over a 25 and 30 year financing period respectively.

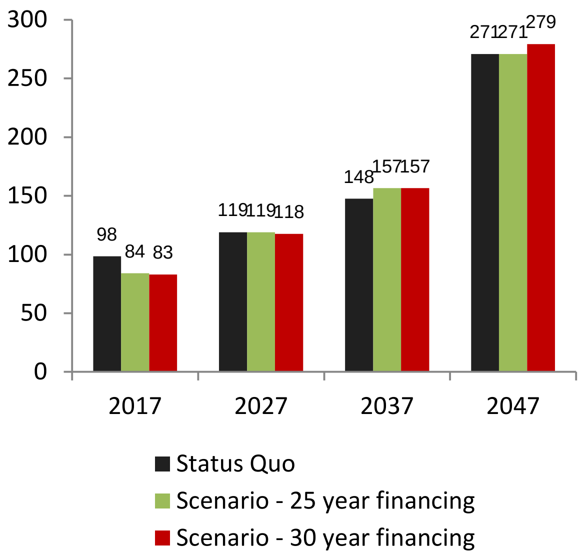



- By **borrowing up to $65 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $25-$28/month** at the cost of **increased future electricity bills over 12-17 years of up to $46-$51/month** above the true cost of electricity production.

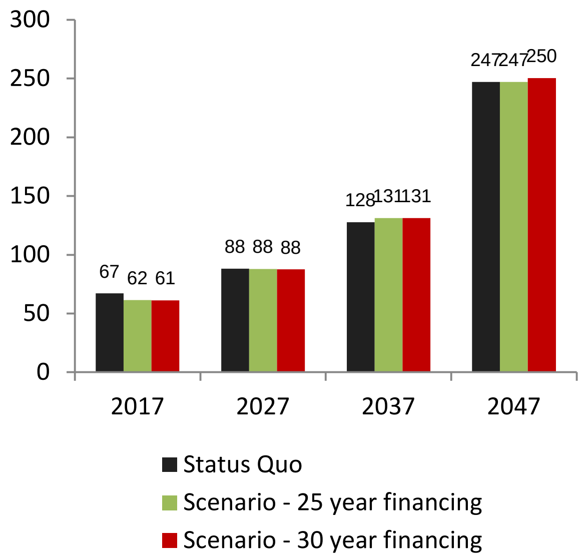
# GA Financing – Illustrative Impact for Large Industrial Electricity Consumers

- Below graphs illustrate the estimated impact under the moderate GA financing scenario for an average Class A electricity consumer, a consumer that pays low GA (i.e., pulp and paper) and high GA (i.e., refining and chemical manufacturing).

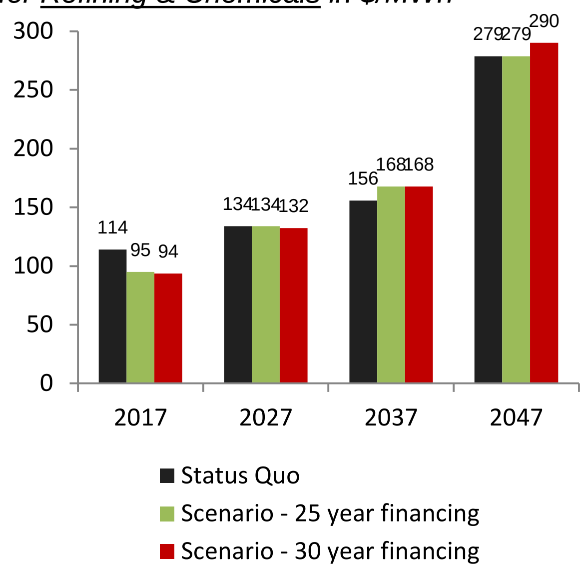
**Estimated All-In Electricity Price**
*for Average Class A in $/MWh*




**Estimated All-In Electricity Price**
*for Pulp & Paper in $/MWh*

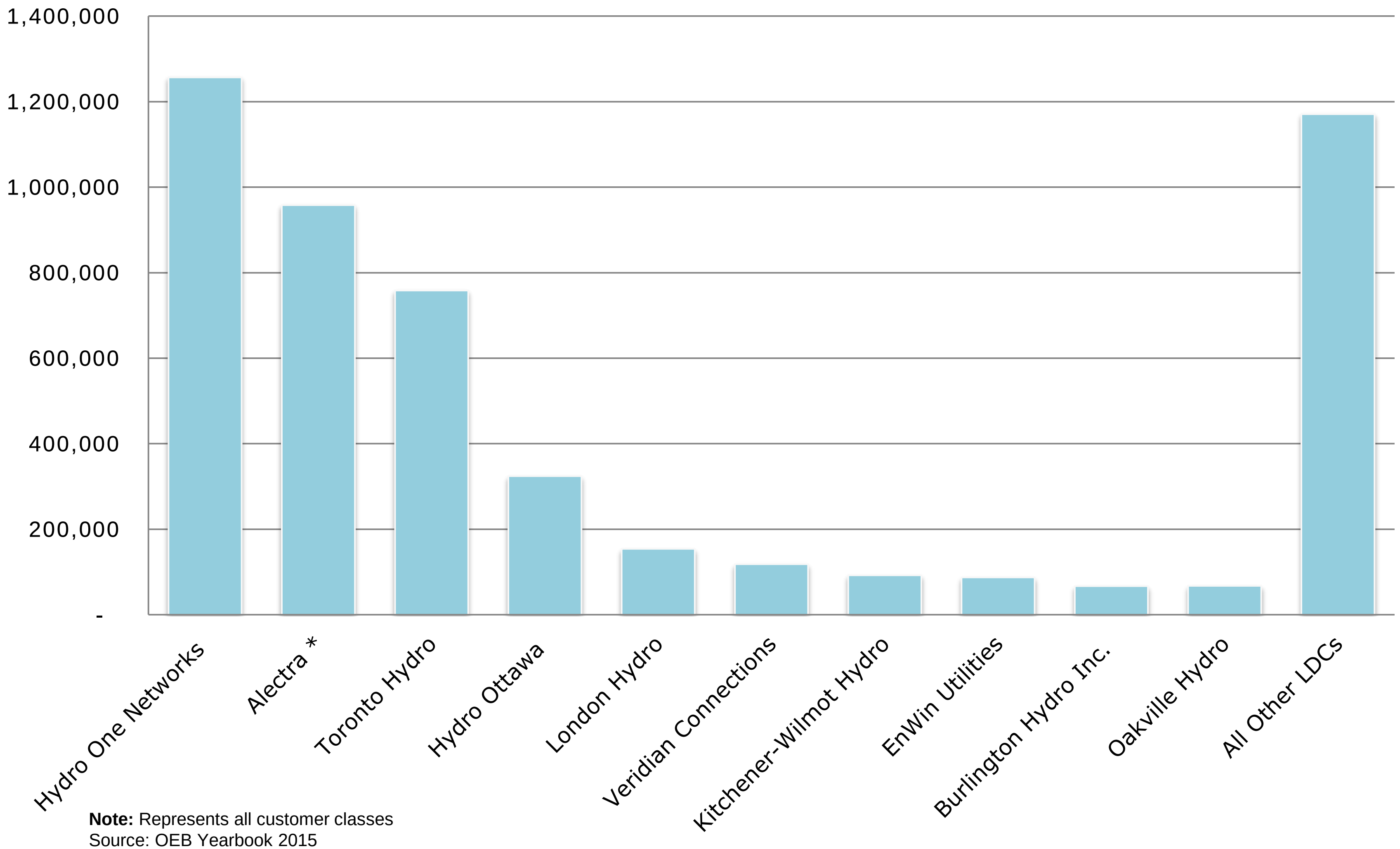



**Estimated All-In Electricity Price**
*for Refining & Chemicals in $/MWh*




**Note:** Assumes that demand by industrial sector continues at average 2011-2015 levels.

# Largest LDCs by Customer Base




**Note:** Represents all customer classes
Source: OEB Yearbook 2015
*Recently approved merger of Powerstream, Enersource, Horizon, and Hydro One Brampton

# 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 contract holders 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.

# 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.

- The Province is not a party to the contracts and has never been involved in the negotiation of the contracts themselves. 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 also required to ascertain whether there is scope within the existing contracts for IESO to renegotiate their terms in this manner.

- 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.

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

# 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.
- 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 | |

# 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.
  - **Illustrative Example:** New contract for 27 years at $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 | | |

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

- Below are illustrative estimates of potential GA savings if all contracts for large FIT and GEIA wind and solar projects in commercial operation are renegotiated according to the approaches illustrated above.
- Estimates are for large (10 MW or greater) FIT 1 and GEIA wind and solar projects in commercial operation, totalling about 2,700 MW of wind and about 900 MW of solar capacity. A 10 year contract extension is assumed at a price of:
  - **For Wind:** LRP I low weighted wind price of $64.5/MWh
  - **For Solar:** LRP I low weighted solar price of $141.5/MWh

**Potential Approach 1:**

| | **Current Contracts*** | **New Extended Contracts** |
|---|---|---|
| Total Value (NPV 2017) | $22.9 Billion | $22.8 Billion |
| Average Annual Contract Value (First 5 Years) | $1.5 Billion | $1.3 Billion |
| *Figures assume projects remain operational after contract expiry at the LRP I low weighted price inflated to the year of contract expiry, as per OPO assumptions . | | |

**Potential Approach 2"**

| | **Current Contracts** | **New Extended Contracts** |
|---|---|---|
| Total Value (NPV 2017) | $ 22.9 Billion | $ 25.3 Billion |
| Average Annual Contract Value (First 5 Years) | 1.5 Billion | $1.0 Billion |

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

- Contract re-negotiations could be piloted with large wind and solar contract holders.
- For example, the top 5 contract holders by portfolio value (online projects 10 MW and larger) include:

| Contract Holder | Technology | # of Contracts | Capacity (MW) | Estimated Value (NPV 2017) |
|---|---|---|---|---|
| Samsung | Wind & Solar | 5 | 799 | $4.6 Billion |
| NextERA | Wind | 6 | 534 | $2.7 Billion |
| Pattern / Capital Power | Wind | 1 | 270 | $1.5 Billion |
| ENGIE | Wind | 4 | 265 | $1.2 Billion |
| Northland Power | Wind & Solar | 15 | 290 | $1.2 Billion |

# Other Options Considered – Typical Residential Electricity Consumer

| *$/750kWh* | **2017** | **2018** | **2019** | **2020** | **2021** | **2022** | **Timing of Benefit** |
|---|---|---|---|---|---|---|---|
| Conservation Funding Options | | | | | | | |
| a. Amortize Conservation Program Costs (15-Year Amortization) | 1.62 | 1.88 | 1.16 | 1.20 | 0.82 | 0.69 | Immediate |
| b. 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 |
| Cancel LRP I | - | - | TBD | TBD | TBD | TBD | Medium-Term |
| Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, etc.) | - | - | - | 2.16 | 2.16 | 2.17 | Medium to Long-Term |
| Dedicate Departure Tax | 1.39 | 1.39 | 1.39 | 1.39 | 1.39 | 1.39 | Immediate |
| Give Residential Consumers More Rate Choices | - | - | - | - | - | - | n/a |
| Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)** | - | - | - | - | - | - | n/a |

**Note:** The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 1 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).

# Options Considered – Average Industrial Electricity Consumers

| *$/MWh* | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | Timing of Benefit |
|---|---|---|---|---|---|---|---|
| Conservation Funding Options | | | | | | | |
| a. Amortize Conservation Program Costs (15-Year Amortization) | 1.12 | 1.30 | 0.80 | 0.83 | 0.57 | 0.47 | Immediate |
| b. 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 |
| Cancel LRP I | - | - | TBD | TBD | TBD | TBD | Medium-Term |
| Expand the Scope of Trillium Trust to Make Investments in Energy Infrastructure (e.g., Transmission upgrade, etc.) | - | - | - | 1.79 | 1.79 | 1.79 | Medium to Long-Term |
| Dedicate Departure Tax | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | Immediate |
| Give Residential Consumers More Rate Choices | - | - | - | - | - | - | n/a |
| Help Small Business Manage Their Electricity Costs (i.e., End DRC early for Class B electricity consumers)** | - | - | - | - | - | - | n/a |

**Note:** The above initiatives will provide similar benefits for non-RPP Class B electricity consumers. Proposal 1 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).