Ontario

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.

Options

- In recognition of the costs borne by ratepayers related to decarbonizing and modernizing the province's electricity sector, options for further rate mitigation include:

  1. Global Adjustment (GA) Financing
  2. Delivery Rate Relief
  3. Other Electricity Support Programs Funded Through the Tax-base:
     - Ontario Electricity Support Program (OESP);
     - Low-Income Conservation; and
     - First Nations Rate.

- As an alternative to the GA financing, in addition to Delivery Rate Relief and Other Electricity Support Programs Funded Through the Tax-base, other mitigation measures could be pursued, including:

  1. Enhanced Tax-based RPP Rebate (5%)
  2. Contract Renegotiations
     - Contract Extensions – Wind and Solar; and
     - Clean Energy Supply (CES) Contracts.
  3. Amortization of Conservation Expenses

Proposed Options – 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.. Delivery Rate Relief	-	TBD	TBD	TBD	TBD	TBD	TBD	Immediate
3. Electricity Support Programs Funded through the Tax-Base								
a. Ontario Electricity Support Program (OESP)*	-	0.83	0.83	0.83	0.83	0.83	0.83	Immediate
b. Low-Income Conservation	-	-	-	-	-	-	-	N/A
c. First Nations Rate	-	-	-	-	-	-	-	N/A

Other Options to Consider:

$/750kWh	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**Timing of Benefit**
1. Enhanced Tax-based RPP Rebate (5%)	-	7.04	7.17	7.31	7.77	7.61	7.83	Immediate
2. Contract Renegotiations								
a. Contract Extensions – Wind and Solar	-	TBD	TBD	TBD	TBD	TBD	TBD	TBD
b. Clean Energy Supply Contract	-	TBD	TBD	TBD	TBD	TBD	TBD	Immediate
3. Conservation Amortization	-	1.62	1.88	1.16	1.20	0.82	0.69	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 Options – Potential Savings for Average Industrial Electricity Consumers

$/MWh	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.. Delivery Rate Relief	-	-	-	-	-	-	-	N/A
3. Electricity Support Programs								
a. Ontario Electricity Support Program (OESP)*	-	1.10	1.10	1.10	1.10	1.10	1.10	Immediate
b. Low-Income Conservation	-	-	-	-	-	-	-	N/A
c. First Nations Rate	-	-	-	-	-	-	-	N/A

Other Options to Consider:

$/750kWh	2016	2017	2018	2019	2020	2021	2022	Timing of Benefit
1. Enhanced Tax-based RPP Rebate (5%)	-	-	-	-	-	-	-	N/A
2. Contract Renegotiations								
a. Contract Extensions – Wind and Solar	-	TBD	TBD	TBD	TBD	TBD	TBD	TBD
b. Clean Energy Supply Contract	-	TBD	TBD	TBD	TBD	TBD	TBD	Immediate
3. Conservation Amortization	-	1.12	1.30	0.80	0.83	0.57	0.47	Immediate

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***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.. Delivery Rate Relief	TBD	TBD	TBD	TBD	TBD
3. Electricity Support Programs					
a. Ontario Electricity Support Program (OESP)*	-	162	225	279	323
b. Low-Income Conservation	-	60	60	60	60
c. First Nations Rate	-	18	18	18	18

Other Options to Consider:

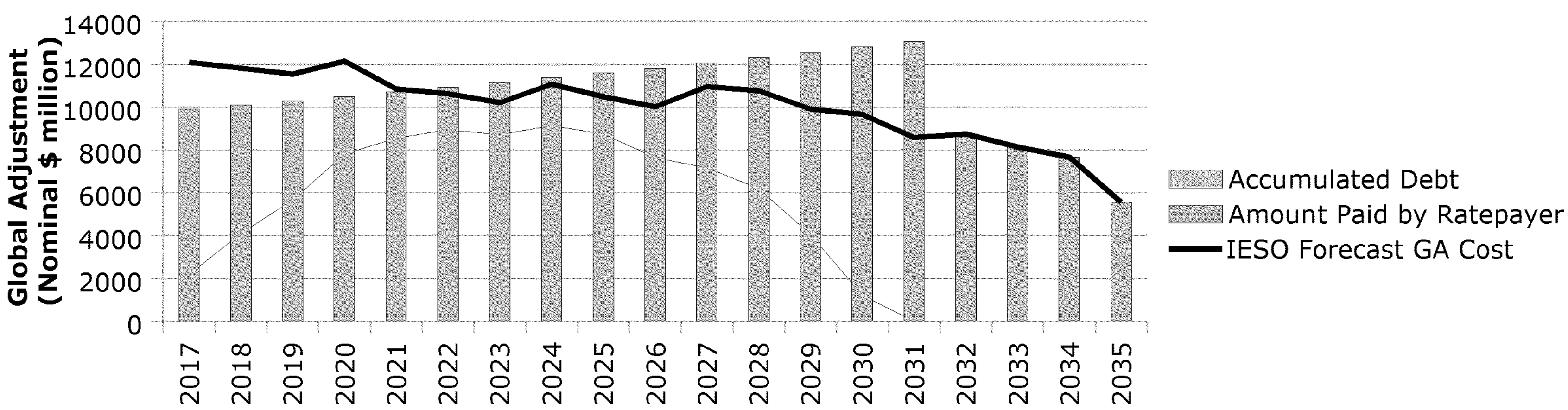
$M	2016-17	2017-18	2018-19	2019-20	2020-21
1. Enhanced Tax-based RPP Rebate (5%)	169	699	679	732	724
2. Alternative to GA Financing – Contract Renegotiations					
a. Contract Extensions – Wind and Solar	-	-	-	-	-
b. Clean Energy Supply Contract	-	-	-	-	-
3. Conservation Amortization	-	-	-	-	-

***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.

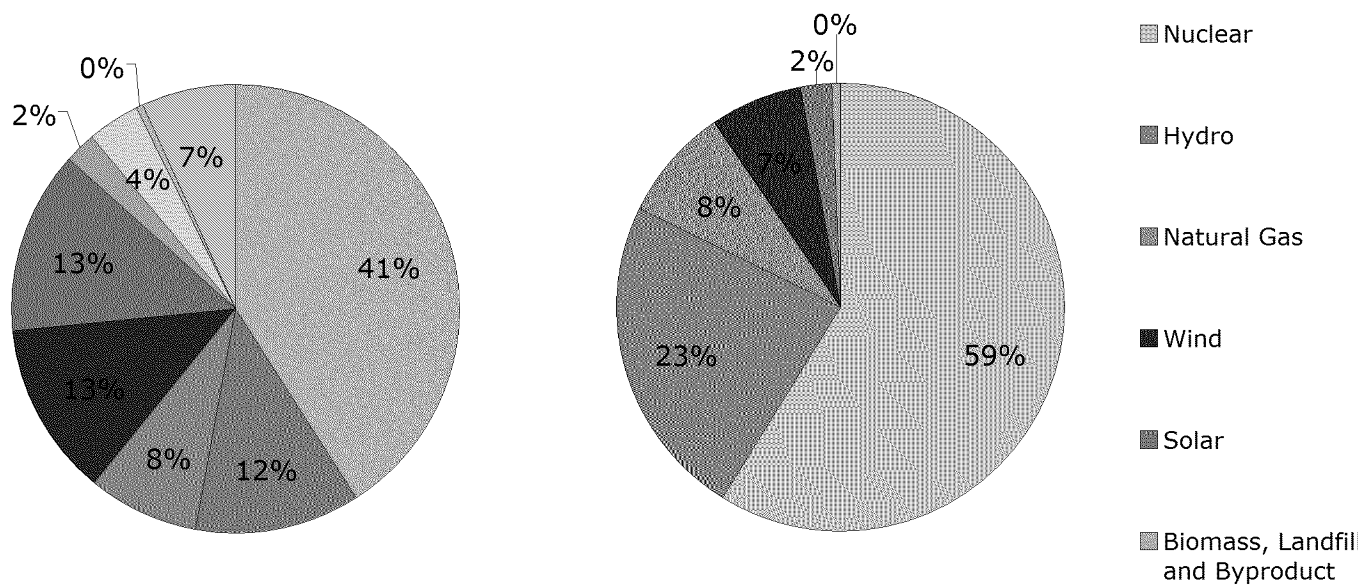


Sample financing: Ratepayers pay less than the cost of GA in early years, borrowing up to $9 billion that is fully paid off in 2031 by charging ratepayers more than the cost of GA in later years.

1. GA Financing – Cost Breakout

- The allocation of GA costs in 2016 is compared to the proportion of generation in the graph below.
- This cost breakdown will evolve over time as 2,181 MW of contracted generation comes online in the coming years.

2016 GA Cost: $12.3 billion **2016 Generation: 155 TWh**



GA ($M)	Gen. (TWh)
5,053	91
1,473	36
985	13
1,552	10
1,630	3
278	1
467	
60	
842	

*OEFC indicates the cost of generator contracts managed by the OEFC which include contracts for natural gas, hydro and biomass generators.
** Conservation measures, not quantified here, serve to reduce Ontario energy demand. Actual electricity generation would be larger than 155 TWh in the absence of conservation programs.

1. GA Financing – Options

1a. Moderate / GA Financing

- The amount of GA paid by ratepayers in 2017 is lowered by $3.1 and $3.3 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 and $1.4 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)

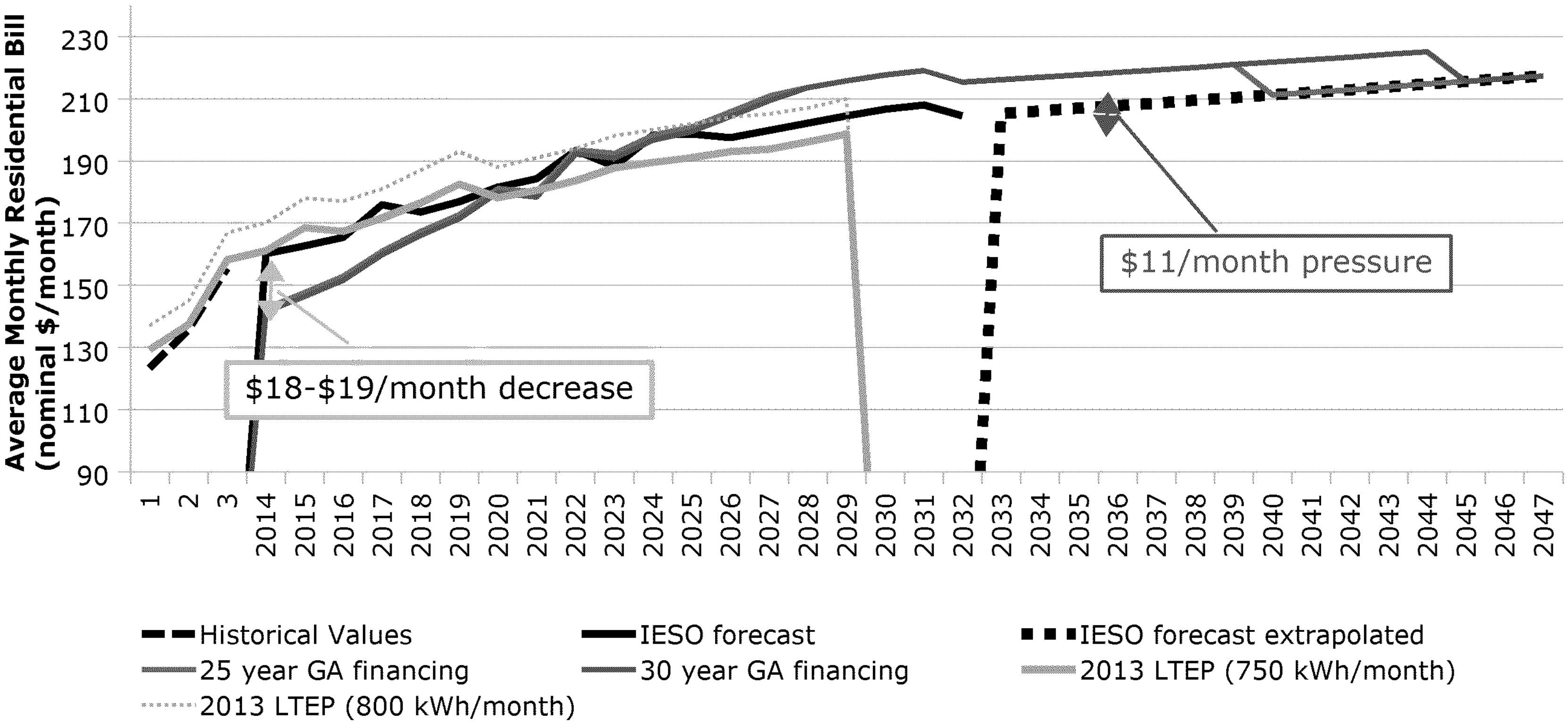
- The amount of GA paid by ratepayers in 2017 is lowered by $2.5 billion below the true cost of GA and increases in each subsequent year until the total amount of money borrowed is paid off.
- Future GA over-payments above the true cost of GA are capped at $2 billion to limit electricity cost increases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

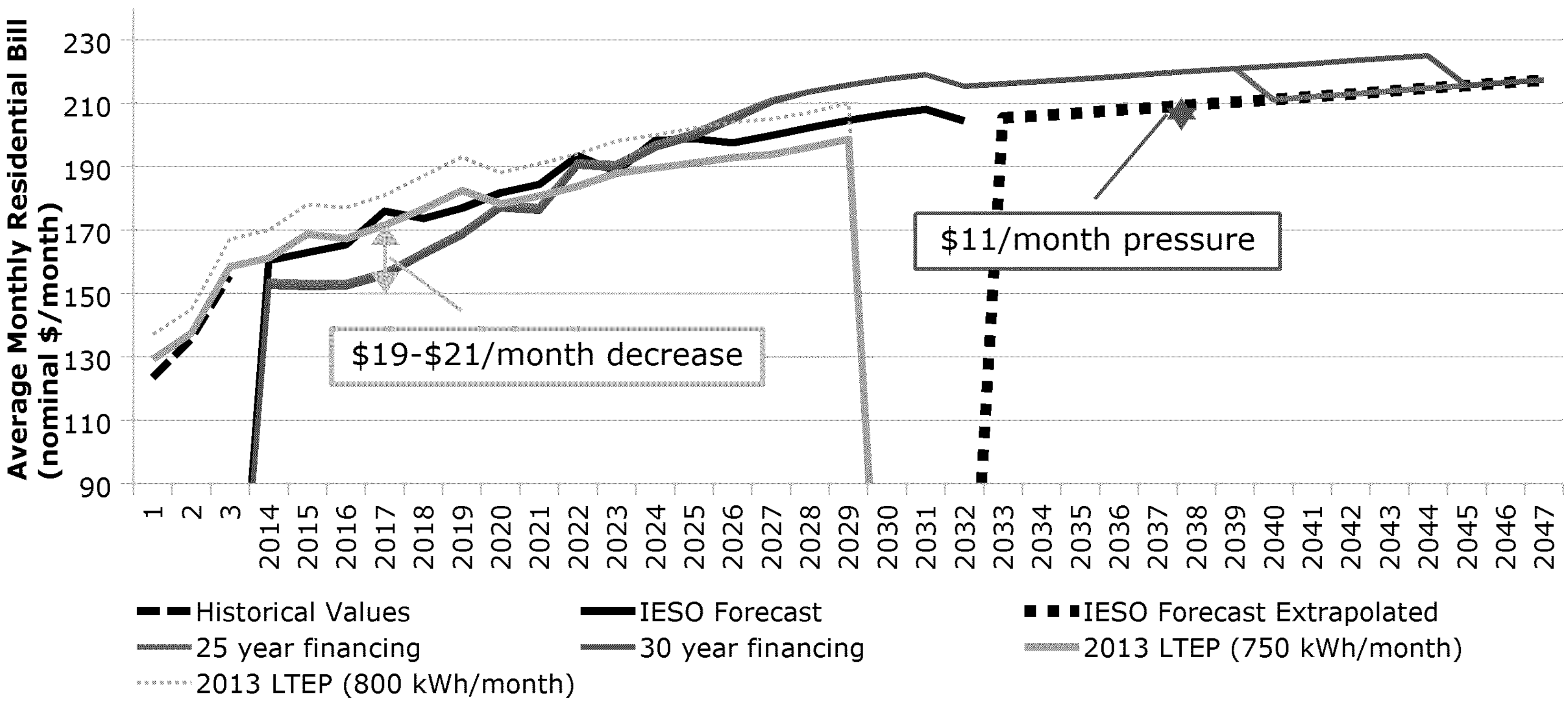
- In this scenario, the starting GA payment from all ratepayers in 2017 is lowered by $3.1 billion (green line) and $3.3 billion (red line) and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 25 and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



- By **borrowing up to $19-$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 (green line) and $1.4 billion (red line), 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 $19-$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 – Accounting (cont'd)

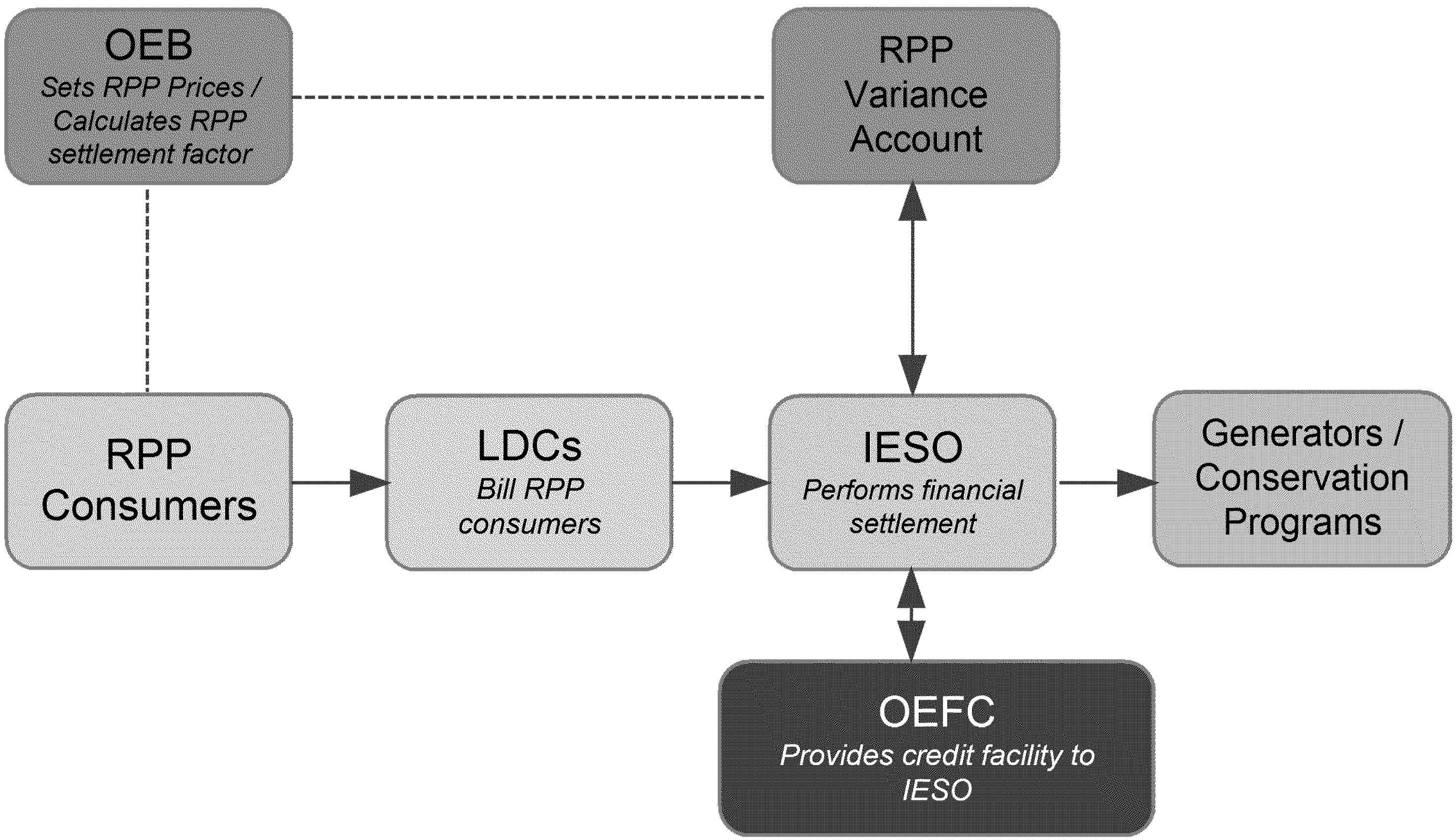
Considerations

- ENERGY continues to work with LSB, IESO, MOF/OFA, TBS and external accountants to identify legislative, regulatory, borrowing and accounting requirements associated with GA financing option.
  - Ongoing analysis 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 (i.e., consolidation).
  - 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).
  - 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.
  - The Auditor General (AG) may comment on the appropriateness of financing the Global Adjustment and/or on the need to consolidate any financing on the Province's books.

- Discussions have broadly focused on:
  - Consolidation risks;
  - Creating an "asset" (and confirm that it meets accounting requirements);
  - Identifying who will hold the asset(s), this could include:
    - Province (e.g., OEFC, etc);
    - IESO;
    - LDCs; or
    - New entity.
  - Determine the source of the financing (e.g., third party, OFA, IO, etc)
  - Exploring different recovery / administrative options (e.g., DRC, RPP, etc)

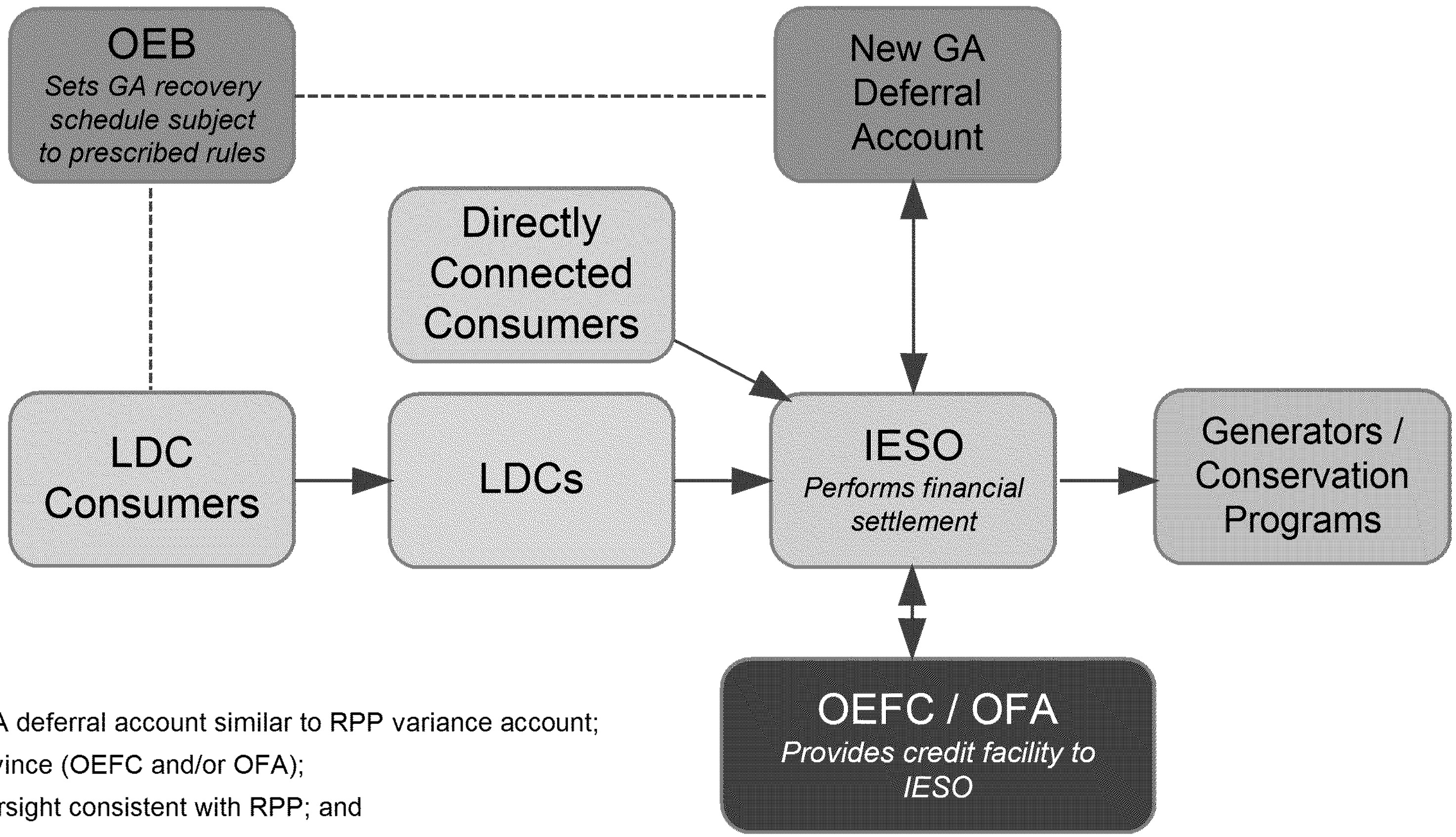
1. GA Financing – Current Regulated Price Plan (RPP) Variance Recovery

- The diagram outlines current Regulated Price Plan (RPP) structure and related flow of funds.



1. GA Financing – Recovery Approach (Option 1)

- The diagram outlines an option that is a variation on the current RPP approach.

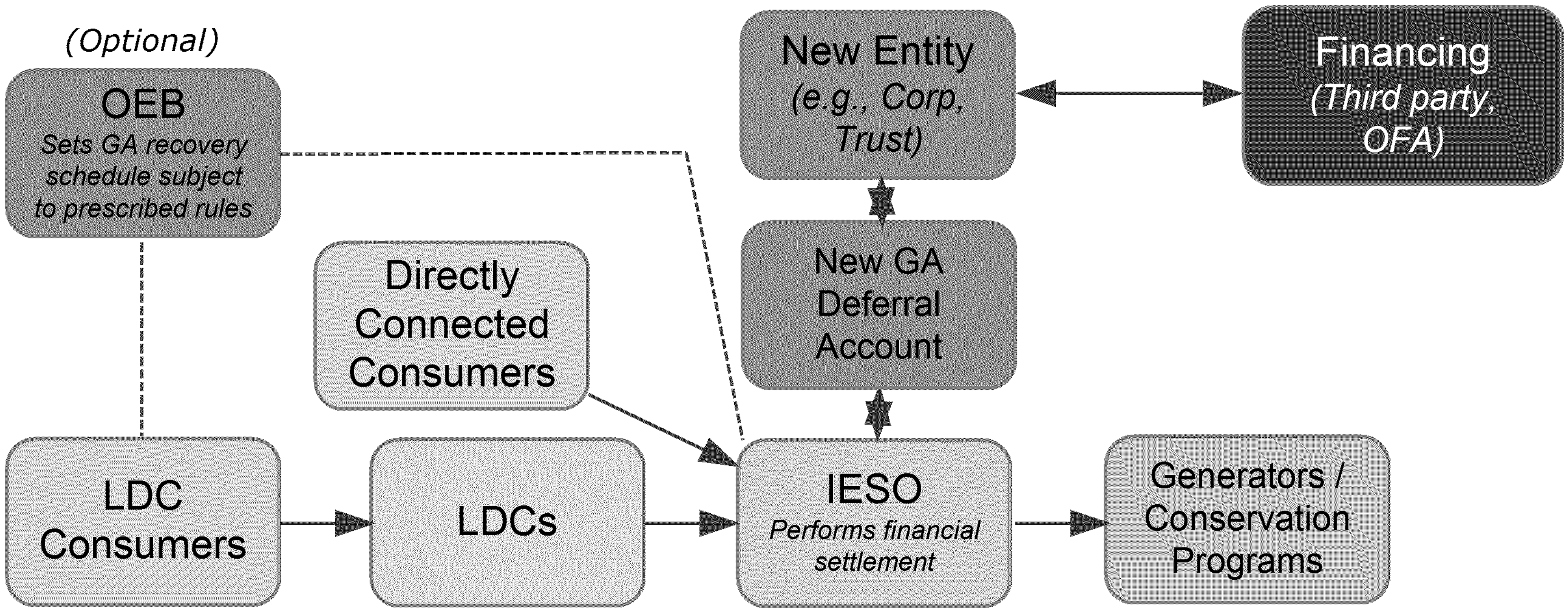


Key Assumptions

- Establish an new GA deferral account similar to RPP variance account;
- Financing from Province (OEFC and/or OFA);
- OEB regulatory oversight consistent with RPP; and
- GA Financing available to all consumers.

1. GA Financing – Recovery Approach (Option 2)

- The diagram outlines an alternative approach that introduces a new arms-length entity.



Key Assumptions

- GA Financing available to all consumers;
- Establish a new arms-length entity (e.g., corporation, trust, etc.) with trustees or a board of either public sector employees or stakeholders / bondholders;
- Purpose of the entity in legislation is to recover deferred GA amounts over 25-30 years from electricity consumers (i.e., ensure guaranteed repayment);
- Financing either through OFA or could be independent or from Province (TBD); and
- Set up outside of the OEB construct (i.e., not regulated). Alternatively, light touch regulatory oversight similar to RPP.

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.

2. Delivery Charge Relief – Background

- The **Delivery** line on a typical consumer bill accounts for roughly 25-35% of the total bill before taxes.
- Delivery covers the costs of getting electricity from generating stations across the province to homes and businesses and combines three cost components of the electricity sector into one line item charge:
  - **Transmission:** The costs of moving electricity across high voltage lines from generating stations to the distribution system. This cost is recovered through a variable charge that is approved by the OEB.
  - **Distribution:** The costs of moving electricity from the transmission system to homes and businesses. Depending on the LDC, distribution costs makes up about 60% to 80% of the Delivery line.
    - This cost is currently recovered through both a variable charge and fixed charge, approved by the OEB. Distribution rates are moving to a fully-fixed charge over next 5 years.
  - **Line Loss:** The costs to recover electricity that is lost as heat when its delivered over a power line, as well as power theft. Each LDC is assigned by the OEB a specific line-loss adjustment factor to reflect their loses particular to their assets. This factor is multiplied against the monthly electricity cost to determine the monthly cost.
- To help mitigate delivery costs, the Province has expanded the Rural or Remote Protection Program (RRRP) to further reduce distribution costs for rural customers across the province.
  - Starting on January 1 2017, 330,000 Hydro One low density (R2 class) customers will receive $60.50 per month in RRRP to bring their total Delivery line costs to roughly $95 for 1,000 kWh/month.

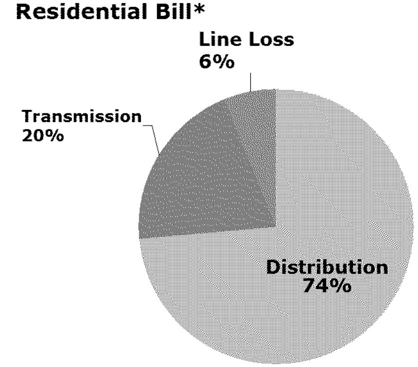
SAMPLE MONTHLY BILL STATEMENT
Anytown Hydro-Electric Limited

Account Number:
000 000 000 000 0000

Meter Number:
00000000

Your Electricity Charges	
Electricity	
Off-Peak @ 8.700 ¢/kWh	41.20
Mid-Peak @ 13.200 ¢/kWh	16.35
On-Peak @ 18.00 ¢/kWh	23.60
Delivery	53.07
Regulatory Charges	4.79
Debt Retirement Charge	0.00
Total Electricity Charges	**$139.00**
HST	18.07
8% Provincial Rebate	(11.12)
Total Amount	**$145.95**

Cost breakdown of Delivery Line for an Average Residential Bill*



* Toronto Hydro Bill @ 750Kwhs

2. Delivery Charge Relief – Proposed Program Overview

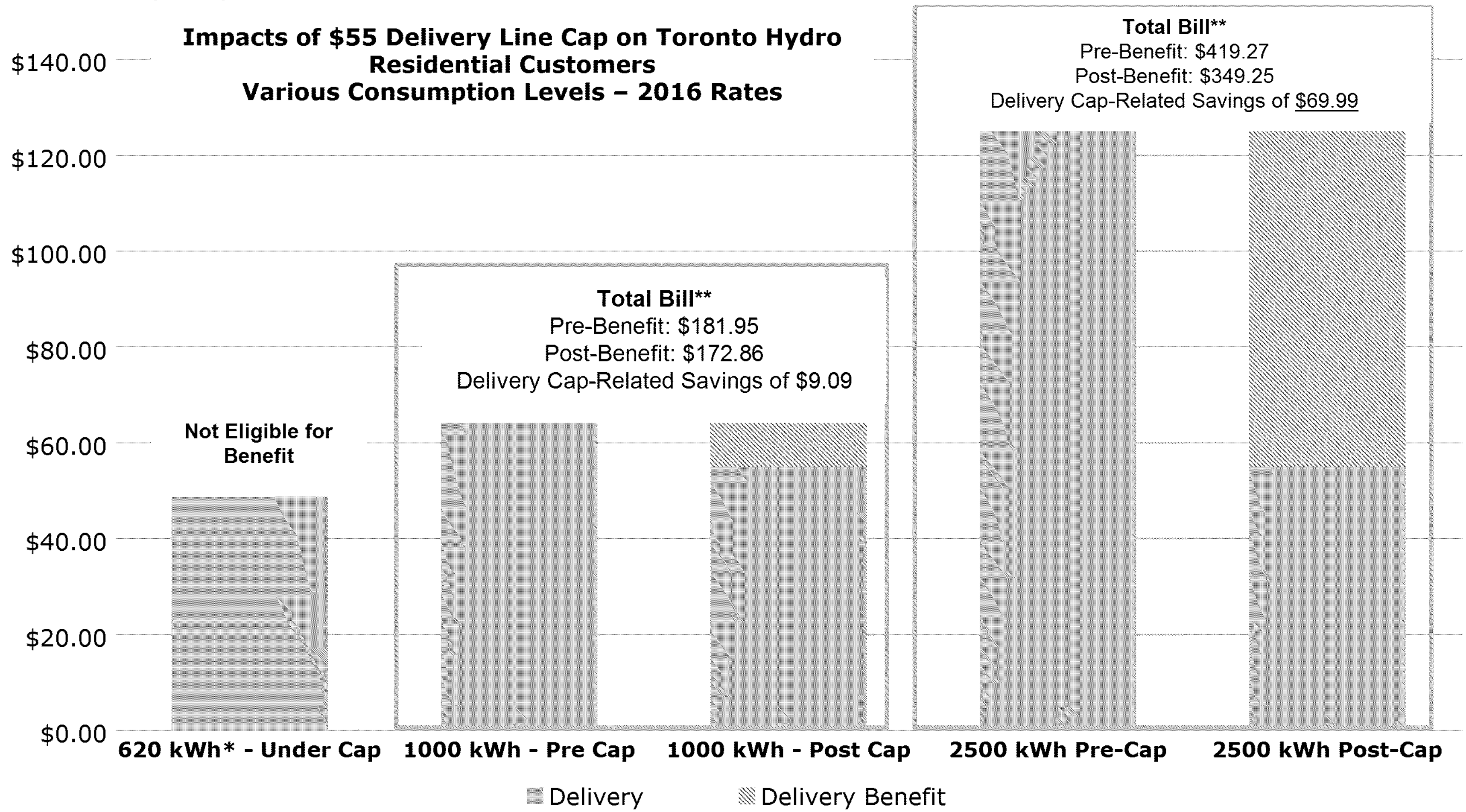
- To provide further relief for customers across the province, the province could create a 'customer-specific' program that would cap the delivery line cost.
- The proposed program would limit the amount an LDC can bill consumers for Delivery at a to-be-determined reasonable cost. Delivery costs that exceed the cap would be covered by support from the fiscal plan.
- The proposed program would target customers within the LDC territory based on their Delivery cost.
  - Delivery costs vary month to month and LDCs will need to keep track of the customers who will receive the receive the additional support.
- Eligibility for increased protection would be based solely on delivery charges above the established threshold and therefore would not be specific to any one LDC. All LDCs must be prepared to offer the program to some of their customers

Considerations

- Costs and ratepayer impacts depend on the number of customers within each LDC whose delivery charges exceed the cap.
  - Costs will fluctuate seasonally and will have year-over-year changes, creating uncertainty in forecasting. Ministry is preparing case study analysis.
- There may be implementation challenges for some LDCs and could take them up to 6 months to implement the program.
- Capping delivery charges may impact OEB rate-setting processes and create disincentives towards utility productivity and performance improvements.

2. Delivery Charge Relief – Proposed Program Overview (cont'd)

- Below is an example of a Toronto Hydro customer at different consumption levels and the level of subsidy they would receive.



**620kWh is the average Toronto Hydro residential consumption level. ENERGY estimates 17.5% of Toronto Hydro consumers average >1000kWh/month.*

*** Includes Electricity, Delivery, and Regulatory Charges. Excludes HST and 8% rebate.*

3a. 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.

3a. 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.

3a. 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.

3b. 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 up to 50% 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.

Other Options to Consider

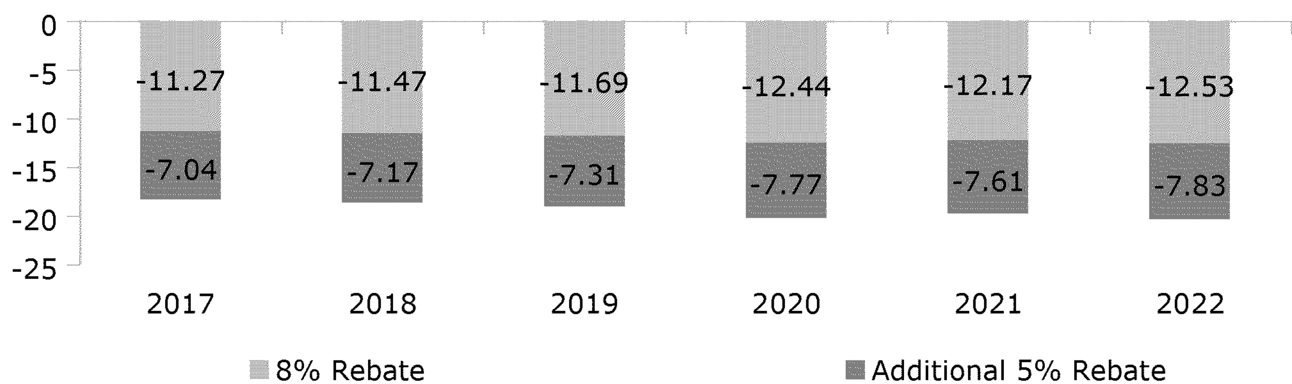
1. Enhanced Tax-Base RPP Rebate (5%)

- 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



1. 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

2a. 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.
- Since extending the contracts would lock in an additional 10 years of GHG emissions free generation to support electrification of transportation and other sectors, consideration could be given to funding the contract extensions with future cap and trade proceeds.

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.

2a. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- 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.

2a. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- 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	

2a. Extend Length of Existing Wind / Solar Contracts (cont'd)

Considerations

- **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		

2a. 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

	Current Contracts*	New Extended Contracts
Total Value (NPV 2017)	$23.3 Billion	$23.1 Billion
Average Annual Contract Value (First 5 Years)	$1.6 Billion	$1.4 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 .		

	Current Contracts	New Extended Contracts
Total Value (NPV 2017)	$23.3 Billion	$25.6 Billion
Average Annual Contract Value (First 5 Years)	$ 1.6 Billion	$0.8 Billion

Source: Figures reflect IESO contract data current as of Sept 2016. Also includes two Phase III solar projects (100 MW combined) that came online in late 2016 not included in Sept 2016 IESO contract data.

2a. 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	7	899	$5.0 Billion
NextERA	Wind	6	534	$2.7 Billion
Northland Power	Wind & Solar	15	290	$1.8 ~~2~~ Billion
Pattern / Capital Power	Wind	1	270	$1.4 ~~5~~ Billion
ENGIE	Wind	4	265	$1.2 Billion
All Other	Wind & Solar	76	1398	$8.1 Billion
Total	**Wind & Solar**	**109**	**3654**	**$20.2 Billion**

Source: IESO contract data current as of Sept 2016.
*Includes two Phase III solar projects (100 MW combined) that came online in late 2016 not included in Sept 2016 IESO contract data.

2b. Clean Energy Supply (CES) Contracts

- There are 13 natural gas facilities operating under Clean Energy Supply (CES) contracts. Given the current excess capacity, some of these facilities could be renegotiated to reduce output in the near term.

- In conjunction, OPG could seek to negotiate outright purchases of certain Ontario gas assets. Given the current excess capacity in electricity supply in Ontario, OPG can seek to negotiate outright purchases of certain Ontario gas assets and reposition them such that ratepayers would pay only for the "current need" component:
  - Contract terms would be renegotiated with the Province to temporarily idle the facilities;
  - Variable expenditures would be largely avoided with the facilities only incurring fixed costs; and
  - Plant life would be extended to a period post-2024 when additional power would be required.

- OPG has estimated monthly residential bill reductions of $2.37 to $4.00 from 2017 to 2019 if such an approach was taken for Ontario's gas portfolio.

- Natural targets would be assets that OPG either jointly owns (e.g., Portland, Brighton Beach) or operate on OPG's site with acquisition funding coming from Provincial borrowing.
  - Although OPG could also look beyond its facilities to the broader natural gas fleet in Ontario.

Considerations

- This proposal would reduce GHGs and provide some near-term cost benefits through lower staffing and maintenance costs:
  - Contract terms would be renegotiated with to temporarily idle the facilities;
  - Variable expenditures would be largely avoided with the facilities only incurring fixed costs; and
  - Plant life would be extended to a period post-2024 when additional power would be required.

- It will likely be challenging to find a willing seller and/or to negotiate a favourable price:
  - Sellers that are approached are in a strong position to extract value from OPG/the Province; and
  - Similarly, OPG's negotiating position would be weakened if this was viewed as part of the broader rate mitigation strategy.

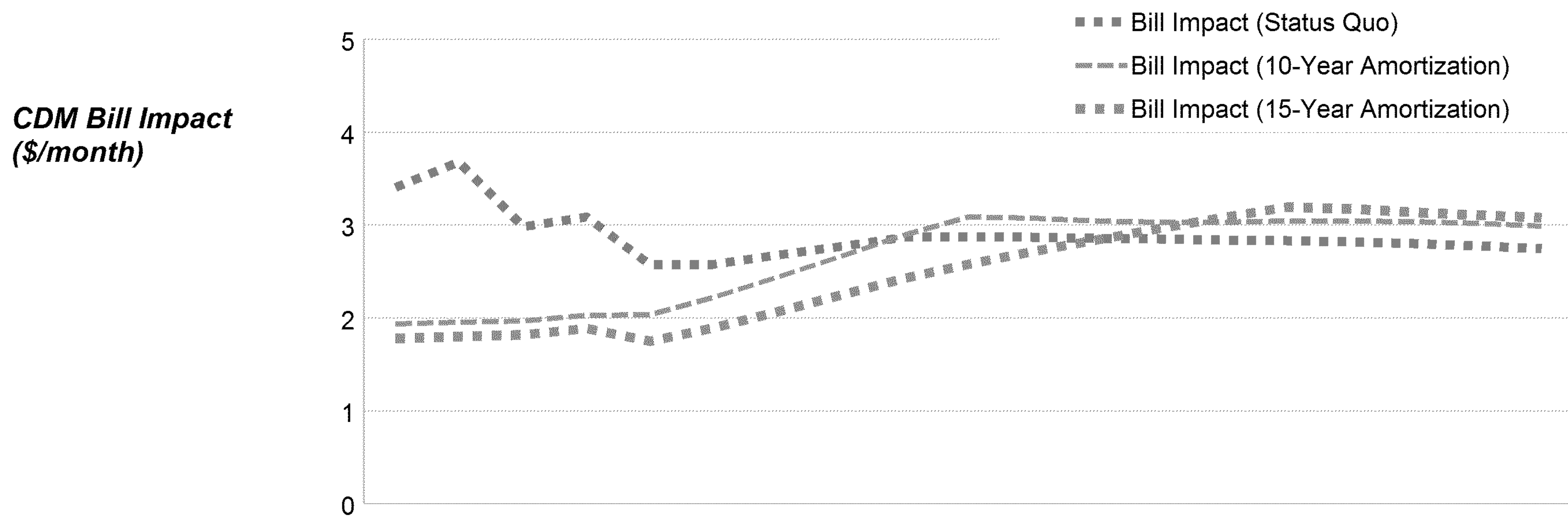
- In the past, OPG and IESO's contract renegotiations have been contentious and lengthy.

3. Amortize Conservation Program Costs

- This option would not be pursued if the Global Adjustment (GA) was financed (Option 1).
- ~$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 would work 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*).

3. Amortize Conservation Program Costs (cont'd)

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



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%.

3. 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.

- **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.

3. 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 has received an opinion on the proposal to amortize CDM costs from IESO's external auditor.
  - Ernst and Young indicated that an argument could be made to support the recognition of the costs as an asset as the costs meet essential asset characteristics, as prescribed by PSAB.

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

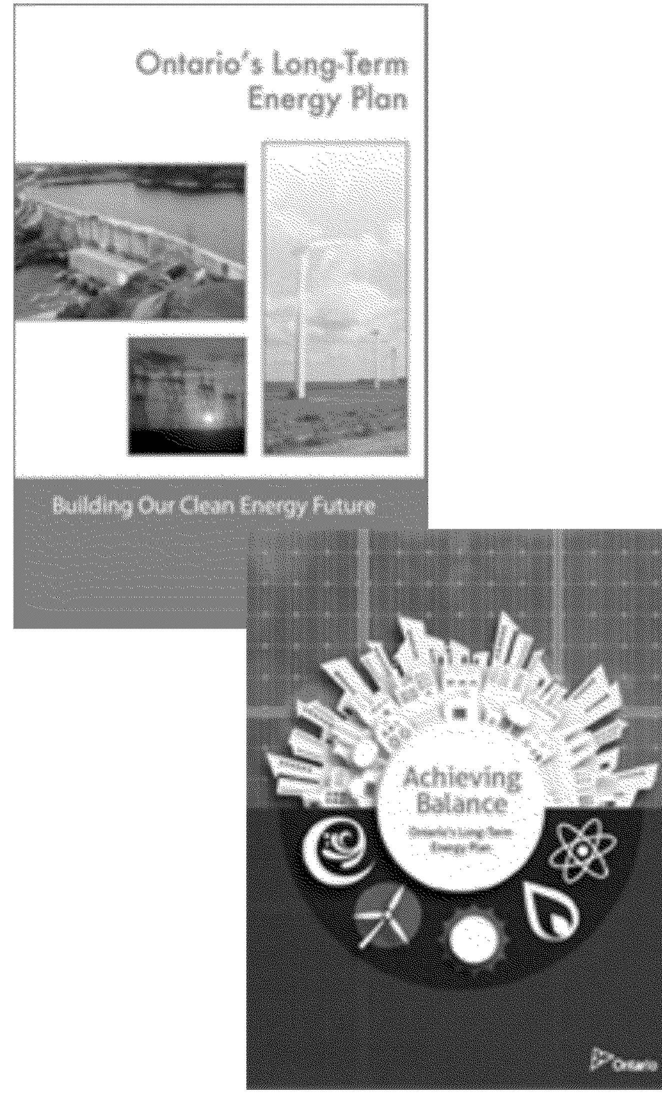
- If there is a desire to pursue this option, ENERGY would seek a formal opinion from the OPC on whether CDM costs could be amortized according to rate-regulated accounting standards, ENERGY would send its note along with IESO external auditor's opinion to OPC.
  - In 2013 when this option had been explored, staff at the OPC agreed with the view that amortized conservation costs can be considered as assets, but noted that the Auditor General may disagree with considering amortized conservation costs as assets.

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

Long-Term Energy Plan

Longer-Term Energy Plan – Overview

- The Long-Term Energy Plan (LTEP) is the energy sector's roadmap, with a focus on integrated policy and setting the direction for Ontario's energy future.
- The 2013 LTEP included content on both Ontario's electricity as well as fuels sub-sectors. The next LTEP will integrate the electricity and fuels sub-sectors to provide a complete picture of Ontario's energy system.
- Developing the LTEP is a highly collaborative process in which ENERGY and IESO directly engage with stakeholders, indigenous communities and the public.
- The Ministry sought stakeholder as well as public feedback through in-person engagement sessions, online tools, and an Environmental Registry posting.
- The Ministry is currently developing the next LTEP, and is targeting a tentative April 2017 release date.



LTEP – Process and Timeline

Jan - Feb
Policy Development

- Ministry staff to review engagement feedback and to provide recommendations for DMO/ MO and Minister on LTEP policies and themes.

Feb - March
Modeling

- Additional modelling to inform potential initiatives and themes will be made to IESO/other modelers to update outlooks.
- Policy decisions may be adjusted based on modeling outcomes.

March
Plan development

- Ministry will prepare LTEP submission and IESO/OEB implementation directives for Cabinet Approval.

Early April
Cabinet Approval

- Cabinet approves LTEP document; as well as IESO/OEB implementation directives

Writer to work alongside and participate in briefings and theme development.

Early – Mid April
Finalize and produce document

- Layout/ graphics/ translation of final document
- Ministry staff provide final review

End April
Publish LTEP and implementation directives

- Final LTEP published on ENERGY website
- Minister issues Cabinet-approved implementation directives to IESO & OEB
- LTEP lockup

May – July
Implementation Plan Development

- IESO and OEB develop implementation plans based on directives

Aug – Sept 2017
Implementation Plan Approval

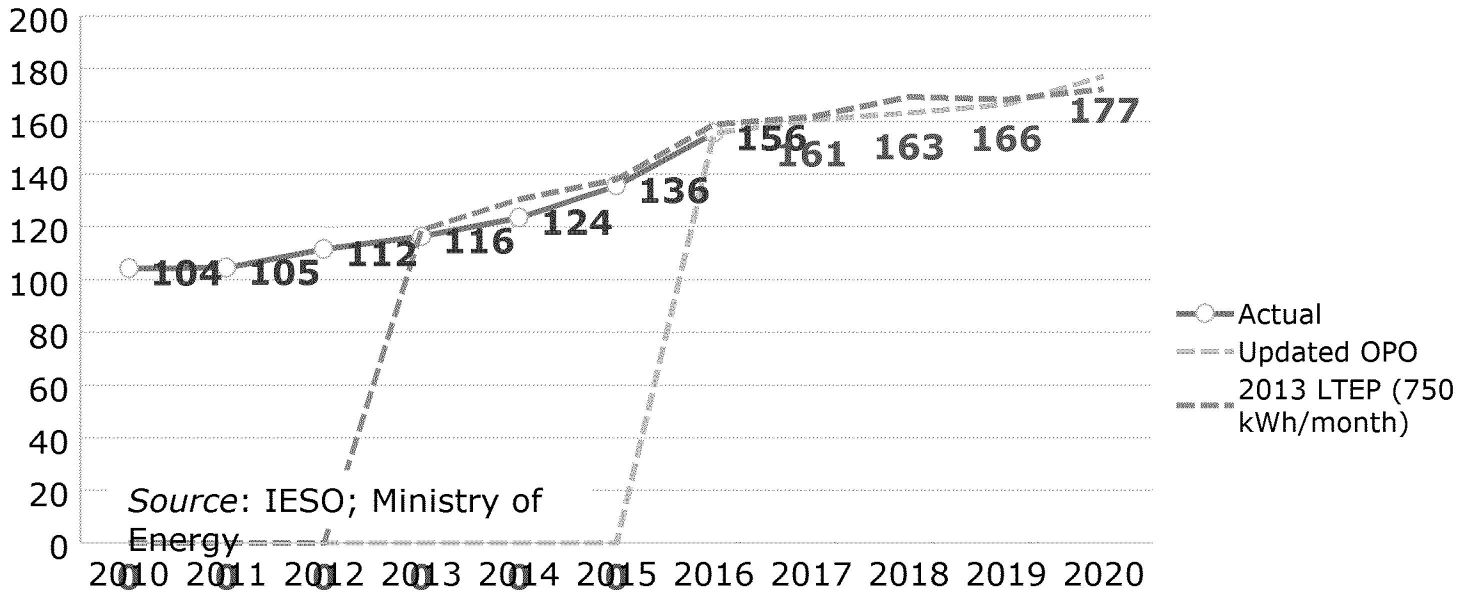
- Implementation plans submitted to Minister of Energy for approval

Appendix

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

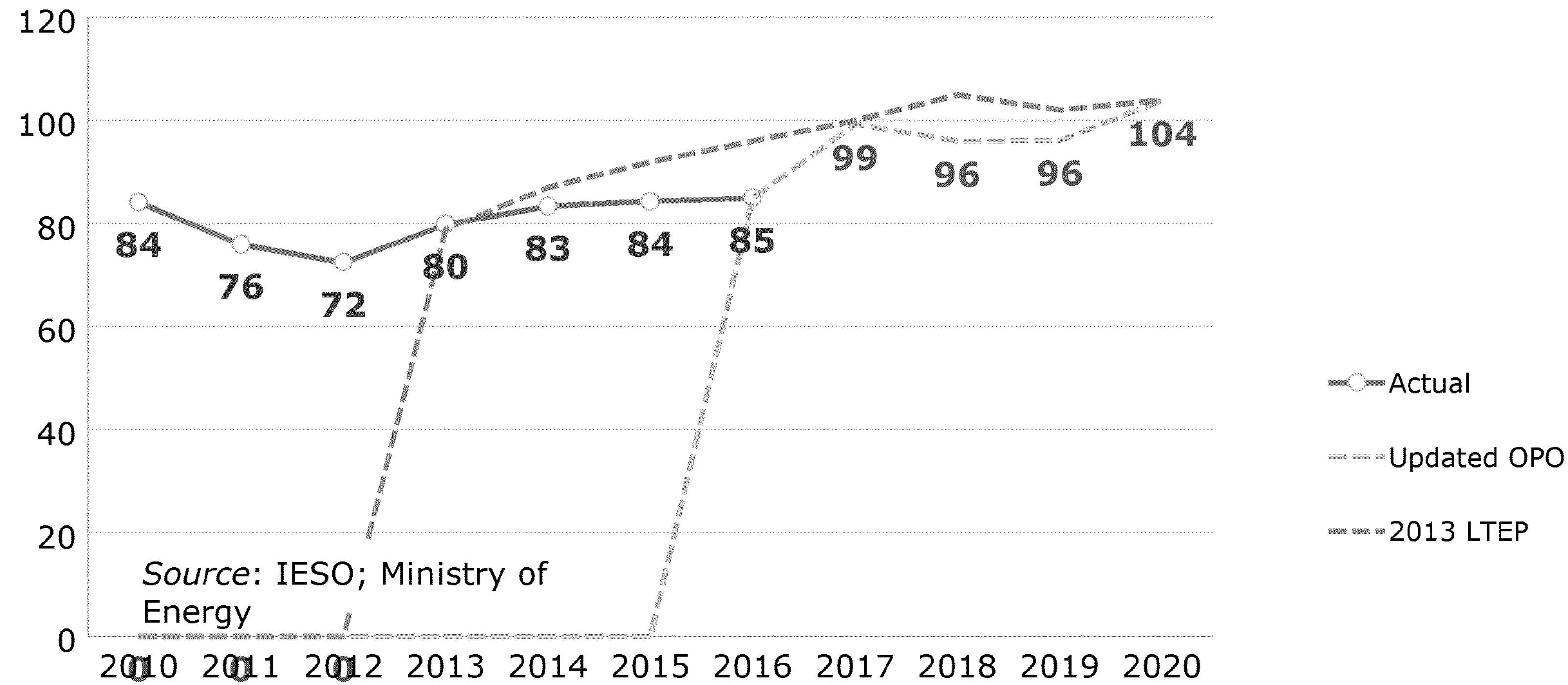


Note: The 2013 LTEP forecast for residential bills was based on 800 kWh/month without RRRP or electric heating; the above has been rebased to 750 kWh/month for comparison purposes. Typical residential are based on Toronto Hydro. The updated OPO forecast above includes the 8% rebate to offset the provincial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

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.

GA Financing – Considerations

Considerations

- 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.
  - 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.

- 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.

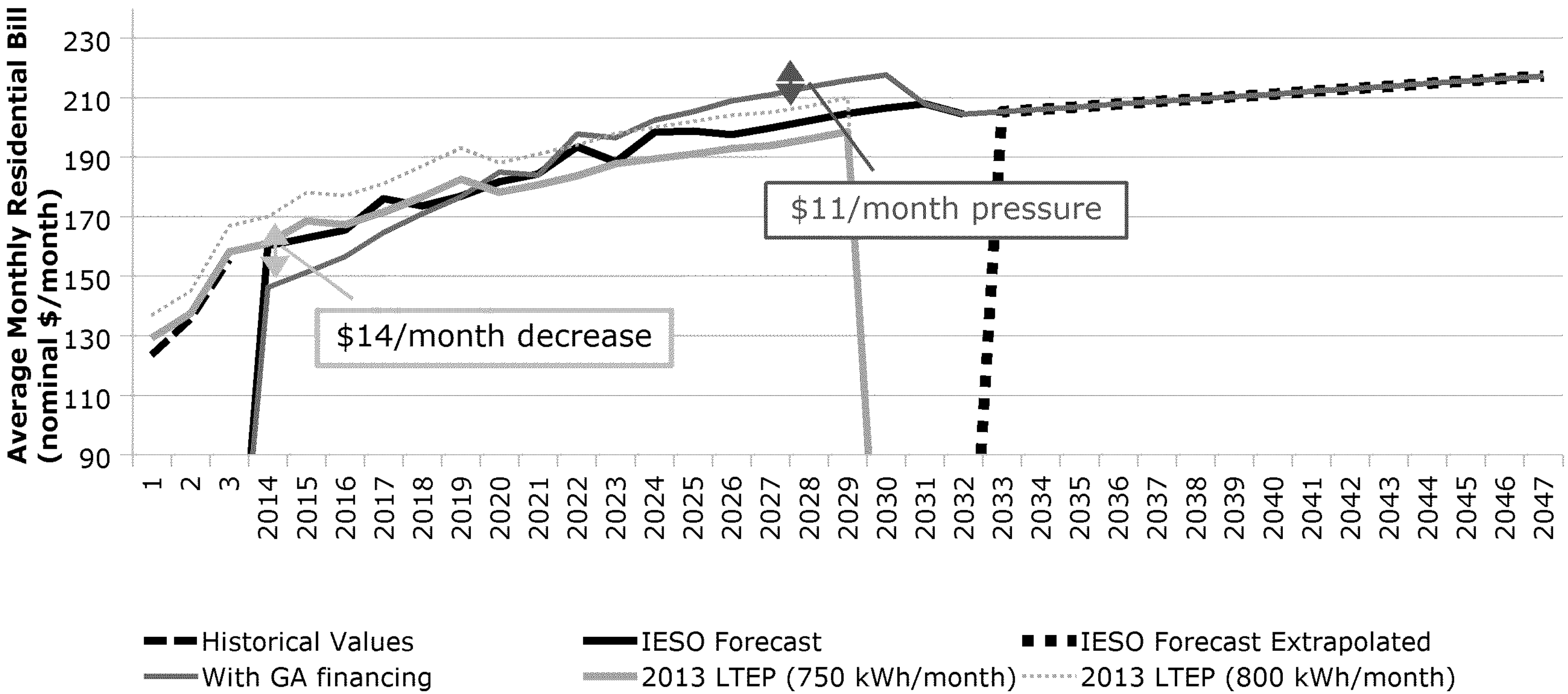
- GA and HOEP provide a natural hedge against each other – when one goes up, the other goes down – keeping total electricity costs relatively stable and predictable. Smoothing only the GA would lead to greater price volatility for consumers unless the schedule and amount of ratepayer payments was defined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

- Some Class A consumers pay limited GA and would receive little benefit under the financing proposal. These consumers also currently pay very low rates. In addition, 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.

- 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.

Low / GA Financing – Impact on Residential Electricity Bills

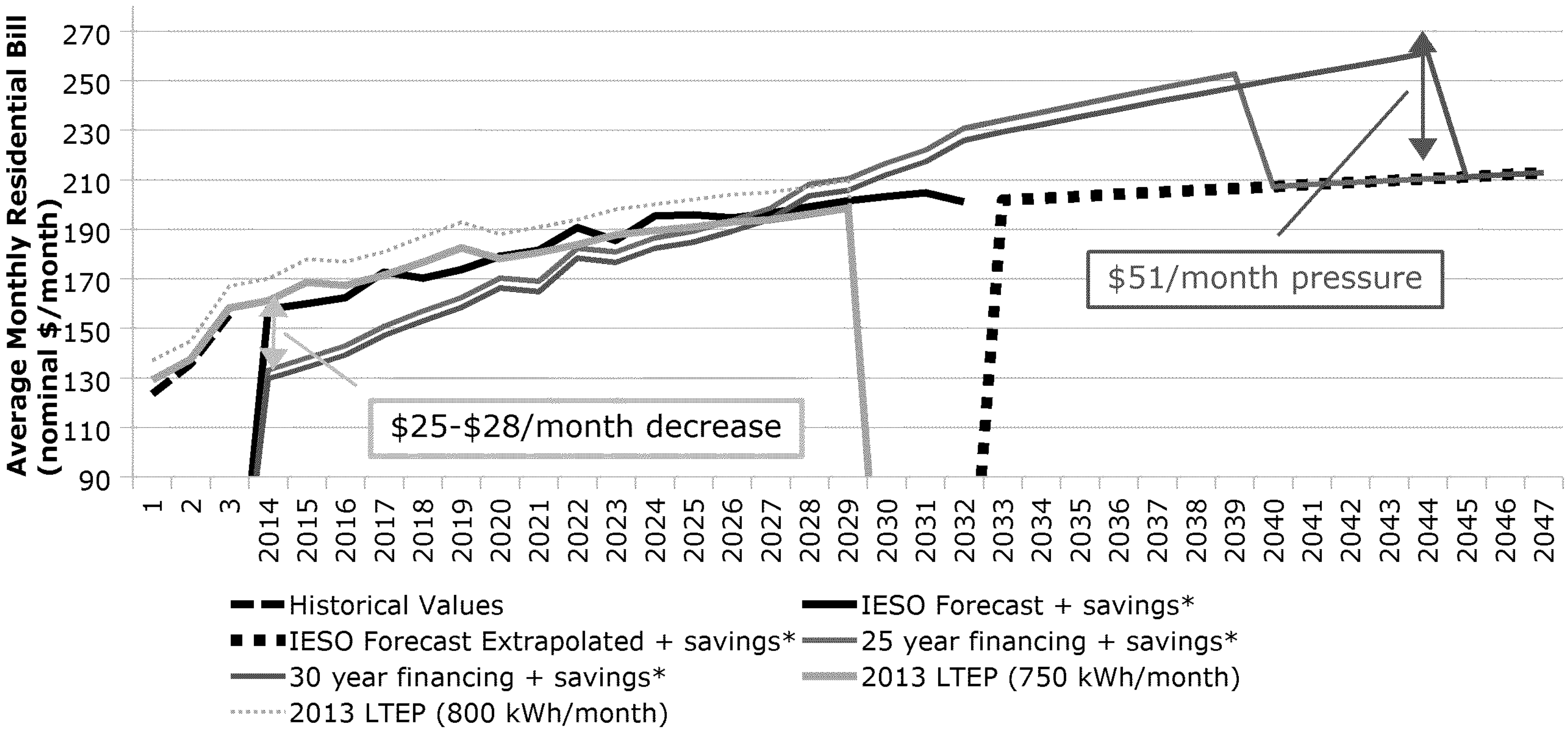
- In this option, the starting GA payment from all ratepayers in 2017 is lowered by $2.5 billion and increases at 2% each year – up to a cap of no more than $2 billion more than the true cost of GA in any year – until the borrowed money is paid back in 2032.



- 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.

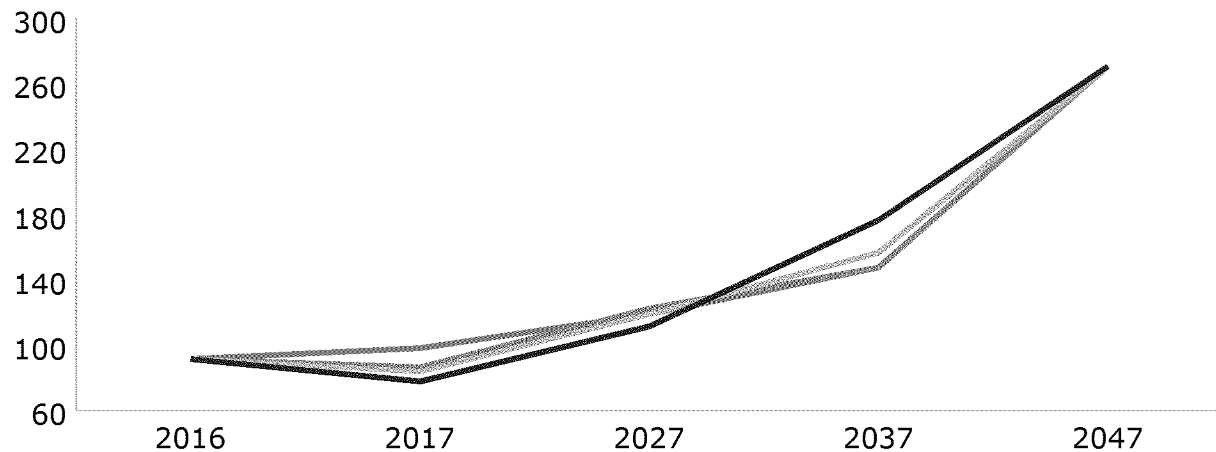


- By **borrowing up to $65 billion**, this scenario results in **a short-term residential electricity cost reduction of up to $25-$28/month** at the cost of **increased future electricity bills over 12-17 years of up to $46-$51/month** above the true cost of electricity production.

GA Financing – 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



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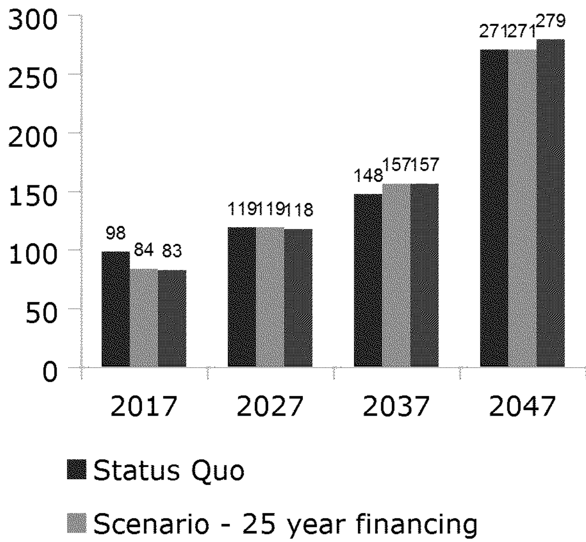
Note: Assumes that demand by industrial sector continues at average 2011-2015 levels. Please see the Appendix or more information on the estimated impact on large industrial electricity consumers.

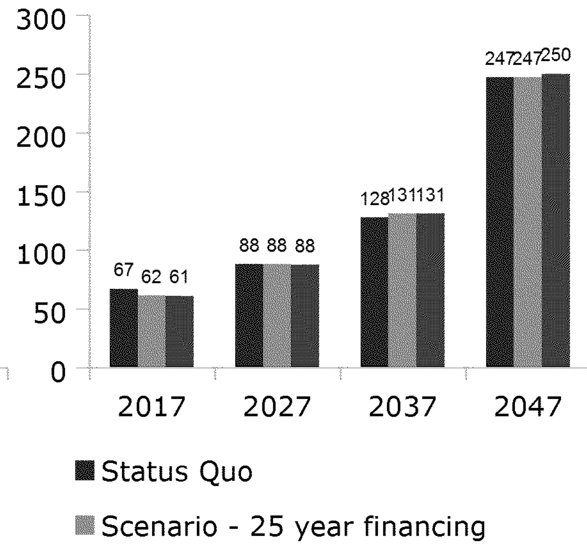
GA Financing – Illustrative Impact for Large Industrial Electricity Consumers

- 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).

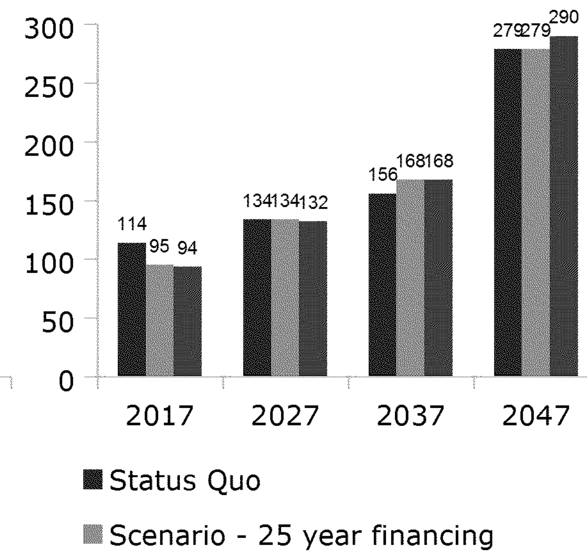
Estimated All-In Electricity Price
for Average Class A in $/MWh



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.

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).