Electricity Relief Scenarios

Item/Description	Ratepayer Benefits	Fiscal Impacts	Considerations

Capping Distribution Costs*
*To the simple average of $30.86 per month across all rate zones based on 2016 residential rates.
 	
<u>Background: Rate-Setting</u>
Currently, distribution rates for LDCs are approved by the OEB through a "cost of service" approach.
• Rates are also divided into rate classes (residential, commercial, etc…). These rates reflect the average cost to serve the customers within the class.
• Hydro One has density based rates, due to its large and varied service area.
 	
Possible Residential Rate Capping Mechanism:
• OEB continues to approve rates based on cost;
• Government prescribes rules for OEB to determine an average LDC distribution rate;
• Government prescribes rules that no LDC can charge its residential customers more than this average rate;
• An LDC with OEB-approved rates greater than this average determines its revenue shortfall and receives funding from tax base to cover shortfall (likely monthly settlement).
	• For 2016, about 2 million residential customers in 23 LDCs across 32 rate zones see benefit.
	• About 1.7 million customers, or 85% of total, are served by 2 LDCs - Hydro One and Toronto Hydro.
	• If rates are capped to ~$30.86/month then Hydro One and Toronto Hydro will see the savings below (at 750Kwh):
	    ○ Hydro One R2: $45.28[1]
	    ○ Hydro One R1: $23.16
	    ○ Hydro One Norfolk: $8.42
	    ○ Hydro One UR: $4.79
	    ○ Hydro One Haldimand: $4.49
	    ○ Hydro One Woodstock: $0.89
	    ○ Toronto: $6.71
	• The remaining approximately 300,000 residential customers served by the remaining 21 LDCs across 25 rate zones see an average benefit of $5.21 per month ranging from $0.23 per month for Westario to $17.87 per month for Algoma.
	• There are roughly 4.6 million residential customers in Ontario as of Dec.31, 2015. Approximately 2.6 million customers see no benefit.
	• Benefit levels and affected customers would change year-to-year as new rates change the average.
		• If the entire RRRP was on the fiscal base and including the proposed distribution cap,it would impact the fiscal by approximately $665M/year
		    ○ However the yearly fiscal impacts will be varied and likely to grow. For example, in order to set rates for 2018, Hydro One will likely be submitting a cost-of-service application to the OEB in 2017. Although subject to OEB approval, this could result in significant rate increases.
		    ○ There is also potential for escalation with Toronto Hydro distribution costs.
		• These 2 LDCs comprise the majority of the costs and their rates are expected to grow faster than the growth in the simple provincial average.
			• LDCs with above average rates (e.g above the $30.86 cap) have costs driven by characteristics unique to their organizations and service territories and are not uniform in their geographic or customer profiles.
			    ○ Costs are driven by 2 LDCs: the most urban (Toronto) and the most rural (Hydro One).
			• Program may pose challenges to the effective regulation of the sector:
			    ○ Potentially rewards least efficient LDCs and incents LDCs to get rates above the average.
			    ○ Weakens OEB's ability to review rate cases in the interest of customers;
			    ○ Would require OEB to be given a taxpayer protection mandate.
			• LDCs could fluctuate above and below the subsidy threshold year-to-year and this could cause extensive variation in rates.
			• Taxpayer subsidizaiton of Hydro One may be controversial following the broadening of ownership.

Item/Description	Ratepayer Benefits	Fiscal Impacts	Considerations
Shifting the higher than market price for FIT contracts to the tax base	Would represent an estimated average residential ratepayer savings of $1.38/month relative to OPO forecasts. Would represent an estimated average industrial ratepayer savings of $1.15/MWh relative to OPO forecasts.	Would represent a total shift of approximately $3.1 billion (NPV 2017) in large FIT value from the rate-base to the tax-base from 2017 to 2033.	Estimates based on 1860 MW of large (>500 kW) FIT wind and 915 MW of large FIT ground mount solar projects in commercial operation. RES I,II,III weighted average wind price of $95.1/MWh was used as a proxy for a competitive market price for wind. Ontario did not procure solar PV competitively prior to LRP I in 2016. As a result, a proxy price of $462/MWh has been developed. This is based on the annual price digression of large-scale solar PV PPAs procured competitively in the US market between 2009 and 2015, applied as an annual increase to the LRP I weighted average solar PV price.

Item/Description	Ratepayer Benefits	Fiscal Impacts	Considerations
Fund up to 20% of electricity infrastructure from the capital plan	• Cost for transmission infrastructure projects that are under development could be offset from capital funding to lower costs to ratepayers when transmitters seek to recover costs through rates. • A fund could also be developed to target projects where current cost responsibility rules force certain customers (e.g. a small Local Distribution Company, a mining project) to carry the majority of costs for the project. In some cases cost impacts are preventing projects with good rationale from moving forward. Offsetting costs for these ratepayers or customers would advance transmission investments in areas that are underserved, have lower system reliability or would create a platform for economic growth	• Scale of fiscal impact would depend on program design, which requires careful consideration. • 20% of the capital plan expenses estimated for 2016/2017 ($11.2B) is ~$2.2B. For context, Hydro One's annual capital budget for transmission is approximately $1 billion per year. • ENERGY is aware of a number of projects under development that could be supported with under $800M (e.g. provincial contribution to the Remote First Nations Connections project, Line in Greenstone, Line and station in Leamington, Red Lake upgrades) and this total value could flow over the next 5 years or amortized over the life of these projects (50+ years). • In addition to projects currently under development, a fund could target transmission lines where reliability performance is substandard, for instance on areas within the transmission system serviced by single-circuit (no redundancy, prevalent in rural and northern areas). Another opportunity would be to target communities seeking to upgrade from single-phase to 3-phase power to attract economic development.	• Transmission infrastructure is owned by private entities who are motivated to capitalize assets to earn a return. Offsetting capital costs would need to be considered in this context to avoid unintended consequences. • Investments beyond transmission, such as microgrids or system upgrades to support grid modernization should also be considered. • The current IESO regional planning process should be leveraged e.g. the funding program could require a proposal to be consistent with the regional plan in its region. • The funding program could target infrastructure investments that support government policy, such as those for which government has deemed the project a priority through an Order-In-Council or where the project is consistent with the CCAP. • One concept that could be considered is that the funding program would advance transmission investments to promote economic growth, but that when new customers connect to the facilities, the fund would be rebalanced by payments from those customers. There already exists a framework under the OEB for this rebalancing when a private entity builds facilities and subsequent customers connect.

<table>
<tr><th>Item/Description</th><th>Ratepayer Benefits</th><th>Fiscal Impacts</th><th>Considerations</th></tr>
<tr>
<td>Fund Ontario’s 2017-2020 electricity conservation initiatives(as part of the Conservation First Framework,the Industrial Accelerator Program and the Demand Response and Conservation Fund) through the Greenhouse Gas Reduction Account (GGRA)</td>
<td>
Total program cost for 2017-2020 electricity conservation initiatives is expected to be ~2.3 billion dollars.
<table>
<tr><th colspan="4">Annual Program Costs ($ Million)</th></tr>
<tr><th>2017</th><th>2018</th><th>2019</th><th>2020</th></tr>
<tr><td>$605 M</td><td>$653 M</td><td>$527 M</td><td>$546 M</td></tr>
</table>
Residential Customers
The average residential electricity consumer could see an electricity bill reduction of ~$3.5 per month, between 2017 and 2020.
Industrial Customers
The average industrial electricity consumer could see a reduction of ~$2.5 per MWh of electricity consumption
</td>
<td>No fiscal impact if funded through the GGRA</td>
<td>

Electricity conservation programs result in reduced GHG emissions by avoiding emissions from peaking natural gas generation.
Electricity conservation programs between 2015 and 2020 are expected to result in 1.3 Mt of GHG reduction in 2020, equivalent to taking 300,000 cars off the road in that year.
Funding conservation programs through GGRA could provide short term relief to consumers while other electricity rate mitigation initiatives are developed (e.g. market renewal, LDC efficiencies).
To facilitate GGRA funding into the global adjustment, legislative changes would need to be made to section 25.33 of the Electricity Act, 1998.
As these funds would be provided through the GGRA, a determination would need to be made on whether they qualify

</td>
</tr>
</table>

Item/Description	Ratepayer Benefits	Fiscal Impacts	Considerations
Funding the Industrial Conservation Initiative (ICI) through the Tax Base ○ Under the ICI, large electricity consumers can decrease their Global Adjustment (GA) charges by reducing their demand during peak hours. Reducing demand during peak hours also benefits the electricity system by deferring the need for new peaking generation. ○ The GA charge reflects the difference between the contracted and regulated cost of generation and the wholesale price of electricity, along with the cost of conservation programs. Currently, ICI shifts a portion of GA costs from large industrials to be paid by remaining electricity consumers.	**$/month*** 2017 6.76 2018 6.62 2019 6.50 2020 6.85 2021 6.10 *750 kWh monthly consumption	**$millions** 2017 1,056 2018 1,032 2019 1,011 2020 1,065 2021 946	• Based on Ministry of Energy forecast for electricity prices and demand. • 2017 expansion of ICI will put some upward pressure on these benefits and impacts. • There is significant uncertainty on the ongoing benefits and impacts due to the dependence of Global Adjustment on the fluctuating wholesale electricity market. ○ For example, the total amount of the GA is expected to decrease in coming years as wholesale electricity prices increase during the nuclear refurbishment period.