Ontario

MINISTRY OF
ENERGY

Rate Mitigation Plan Options

Working Draft

February 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) Smoothing – Provide significant and immediate rate relief through cost deferral of the GA.

  2. Electricity Support Programs to Help the Most Vulnerable – Provide a greater focus on vulnerable consumers:
     - Rural or Remote Electricity Rate Protection (RRRP) Enhancement (Delivery Charge Relief);
     - Ontario Electricity Support Program (OESP) Expansion; and
     - Low-Income Conservation / Affordability Fund .

  3. Ontario Energy Board (OEB) – Identify opportunities for OEB red-tape reduction and future LDC efficiencies and rates.

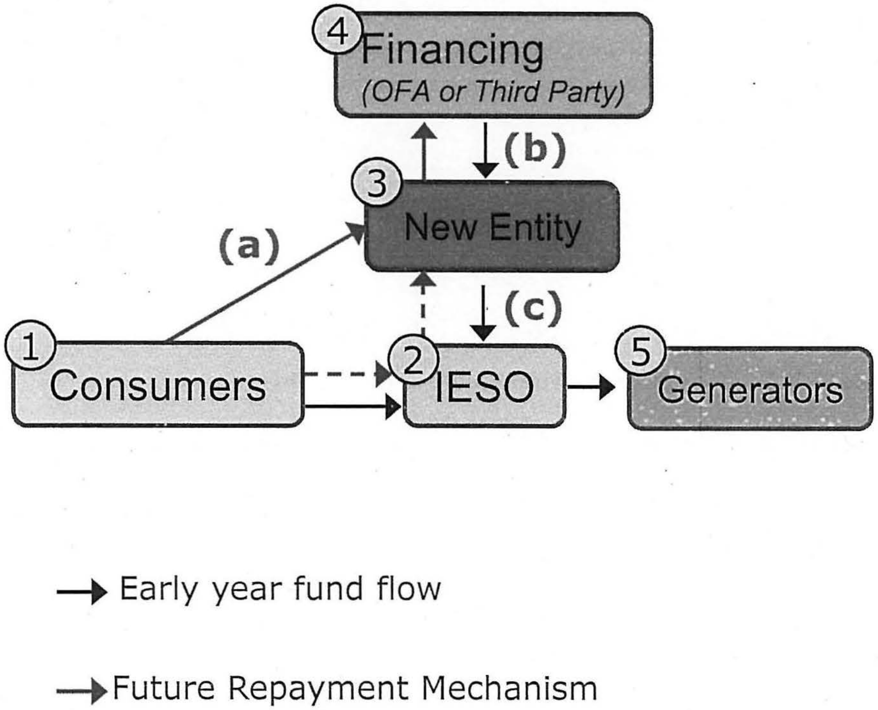
  4. Ontario Power Generation (OPG) – Find further efficiencies in operations and pass on savings to ratepayers.

  5. Independent Electricity System Operator (IESO) – Modernize Ontario's electricity market through electricity Market Renewal initiatives.

GA Smoothing Options (Placeholder)

1. GA Smoothing – Implementation Approach (New Entity)

- The diagram outlines a implementation approach that includes a new entity which would hold the debt and the receivable from ratepayers



1. Electricity Consumers pay IESO a portion of the GA in early years. In the future, consumers would pay all in-year GA costs and repay the New Entity. Customers will not see a change in the structure of their bills (costs should diminish in early years).

2. The IESO pays generators (in early years), partially from consumers and partially financed by the New Entity. **(c)** The IESO would provide collection services to New Entity under a service contract.

3. The New Entity would fund part of the GA and **(a)** would have a legislative right to recover the principle, interest and administrative costs from customers (settled via service agreement with IESO).

4. The OFA or a 3rd party lender would fund the GA shortfall in early years and receive payments from the New Entity as debt is repaid **(b)** the debt would be subject to a contract between the New Entity and the lender.

5. Generators continue to receive payments from IESO according to existing contract / regulatory structures.

1. GA Smoothing – Considerations

Governance

- To achieve the desired accounting treatment, the entity would have to be structured as follows:
  - While the Province would choose the first board of directors or trustees, future directors or trustees would be selected in accordance with a mechanism created at the time the entity is created. The Province would have no ongoing role in appointments or in selection of key personnel, including the CEO.
  - The Province would not have a determining vote in the entity's business decisions. The entity could be structured so that the Province has no vote.
  - The Province would have no recourse to the entity's assets and would not be responsible for the debt.
  - Mechanisms would be required to prevent the Province from dissolving the entity and having access to its assets and obligations.
  - The Province would not be able to change the mission or mandate of the entity, once it is created.
  - The Province would have no right to approve business plans or budgets or to require amendments to them.
  - The Province would not be able to alter the terms of the entity's debt arrangements.
  - The Province would not be able to affect the debt by controlling the entity's financial and operating policies.
  - The Province would not have input into the operational and financial policies of the entity, including accounting, personnel, compensation, collective bargaining or deployment of resources. For example, legislation like the *Broader Public Sector Executive Compensation Act, 2014* and the *Broader Public Sector Accountability Act, 2010* would not apply.

- The implications of designing the entity to meet the accounting control, and creating an entity that the Province does not govern, means that:
  - Staff would not be OPS employees.
  - Oversight would not be provided by Offices of the Legislature (Auditor General, Financial Accountability Officer).
  - The *Freedom of Information and Protection of Privacy Act* would not apply.

- It may be possible to have the OEB provide some oversight through licensing or regulatory proceedings.

1. GA Smoothing – Other Considerations (cont'd)

- **Recovery Mechanism**
  - Province will need to explore different recovery/ administrative options.
  - DRC/RRP/Tax Rebate.
  - Consider whether a one-time, exit payment would be charged to ratepayers that are leaving the electricity system in order to recover foregone deferred charges.
- **Financing**
  - While 3rd party financing would help to meet accounting control tests, the cost may be high
    - The Province may need to internally test the market to determine potential cost of 3rd party financing / securitization.
  - Potential risks that 3rd parties will likely consider when determining cost of capital include:
    - Legislative framework (recovery mechanism);
    - Interest rate changes; and
    - Future electricity demand / customers.
- **Contractual / Legislative Agreements**
  - Either the New Entity or IESO would need a legislative right to recover the principle, interest and administrative costs from customers.
  - Form of an IESO collection services agreement would need to work within IESO's legislative framework, while providing sufficient comfort to the New Entity / 3rd party.
  - We need to consider whether the Province's ability to change legislation undermines the governance choices that we make to achieve the accounting control analysis

2a. RRRP Enhancement – Accelerating Fixed Rate Benefit

- Currently, LDCs recover their costs through a combination of a fixed monthly charge and a volumetric charge based on kilowatt hours used. As a result, customers of the same LDC will be charged different amounts for distribution based on their consumption level.
- However, the OEB has made a determination to establish fixed distribution rates for residential consumers, in recognition that the majority of distribution costs are irrespective of the volume of consumption. The OEB believes moving to fixed rates will:
  - Enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services.
  - Establish a fairer way to recover the costs of providing distribution service.
  - Provide greater revenue stability for distributors, which will position them for technological change in the sector, remove any disincentive to promote conservation, and help with their investment planning.
- Fixed rates will be set at the average consumption level for a rate class in order to recover the same amount of revenue as the mix of fixed and variable charges does today. As a result, below-average volume consumers will experience cost increases and above-average volume consumers will experience cost decreases.
- The OEB is gradually phasing-in the move to fixed rates in order to mitigate the impact of these increases to below-average volume consumers. Most LDCs will receive fully fixed rates in 2019. Hydro One will be transitioned over a longer timeframe (2022-2023).
  - Hydro One's density-based rate classes and recent re-allocation of costs between the classes results in significant impacts for Hydro One low volume consumers. Providing the longer timeframe allows for the impact of the change to be held at less than 10% for low volume customers at the 10th percentile of consumption.

2a. RRRP Enhancement – Accelerating Fixed Rate Benefit Impacts

- Hydro One has estimated that if it accelerated the move to fixed rates effective 2017, the rates would be as follows:
  - R1: $55.70/month – the same cost as a customer who consumes 955kWh/month today.
  - R2: $64.64/month, when factoring in the $60.50 RRRP support – the same cost as a customer who consumes 1200kWh/month today.
- Using sample customer data provided by Hydro One, it is estimated that approximately 2/3rds of Hydro One R1 and R2 customers would experience cost increases if this was implemented:
  - R1: ~146k customers would see cost decreases, and ~298k customers would see cost increases.
  - R2: ~117k customers would see cost decreases, and ~217k customers would see cost increases.
- However, support from the fiscal plan can be used to accelerate the move to fixed rates for those high volume consumers who benefit – leaving low volume consumers to experience no change.
  - Hydro One estimates this would cost $64 million. If the move was expanded to include Hydro One Urban (UR rate class) and Seasonal customers, the cost would be ~$90 million.
  - When layering on the current RRRP support of $242 million, program costs are between $306-$332 million.
  - As the move to fixed rates was completed, fiscal plan support for these customers could be withdrawn.

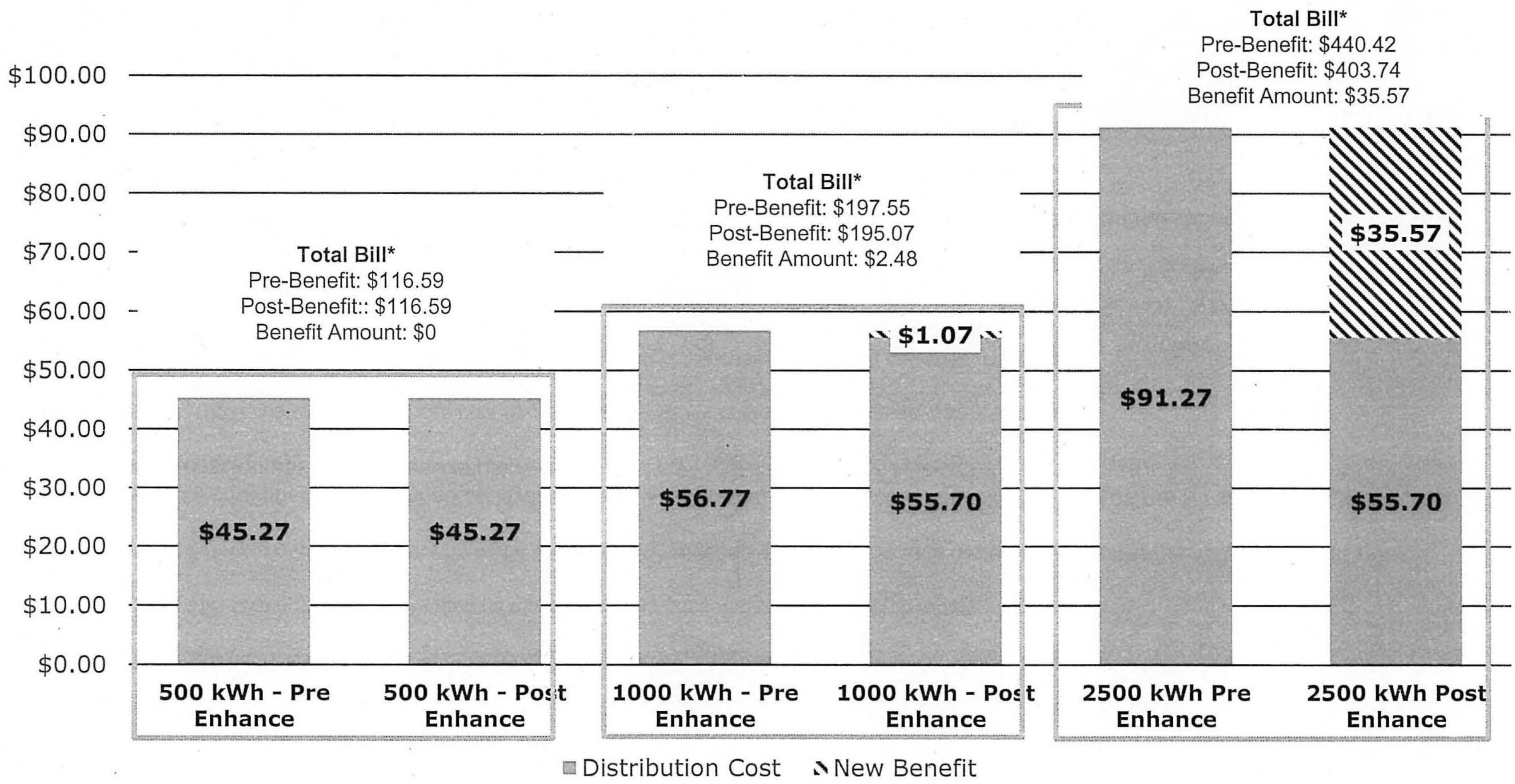
Accelerated Fixed Rate Benefit Fiscal Impact						
	2018	**2019**	**2020**	**2021**	**2022**	**2023**
Fixed Rate Enhancement*	$64M-$90M	$52-$72M	$38M-$54M	$26M-$36M	$13M-$18M	$0
Total RRRP** (inclusive fixed rate enhancement, excluding Algoma Power & Hydro One Remotes)	$306-$332M	$300-$320M	$293-$309M	$287-$297M	$281M-$286M	$275M

**Range depends on if just R1 & R2 or all rate classes. Cost decrease is estimated evenly, which could change based on Hydro One future rate impacts.*

*** Assumes 2.6% annual increase as estimate of average distribution rate increase*

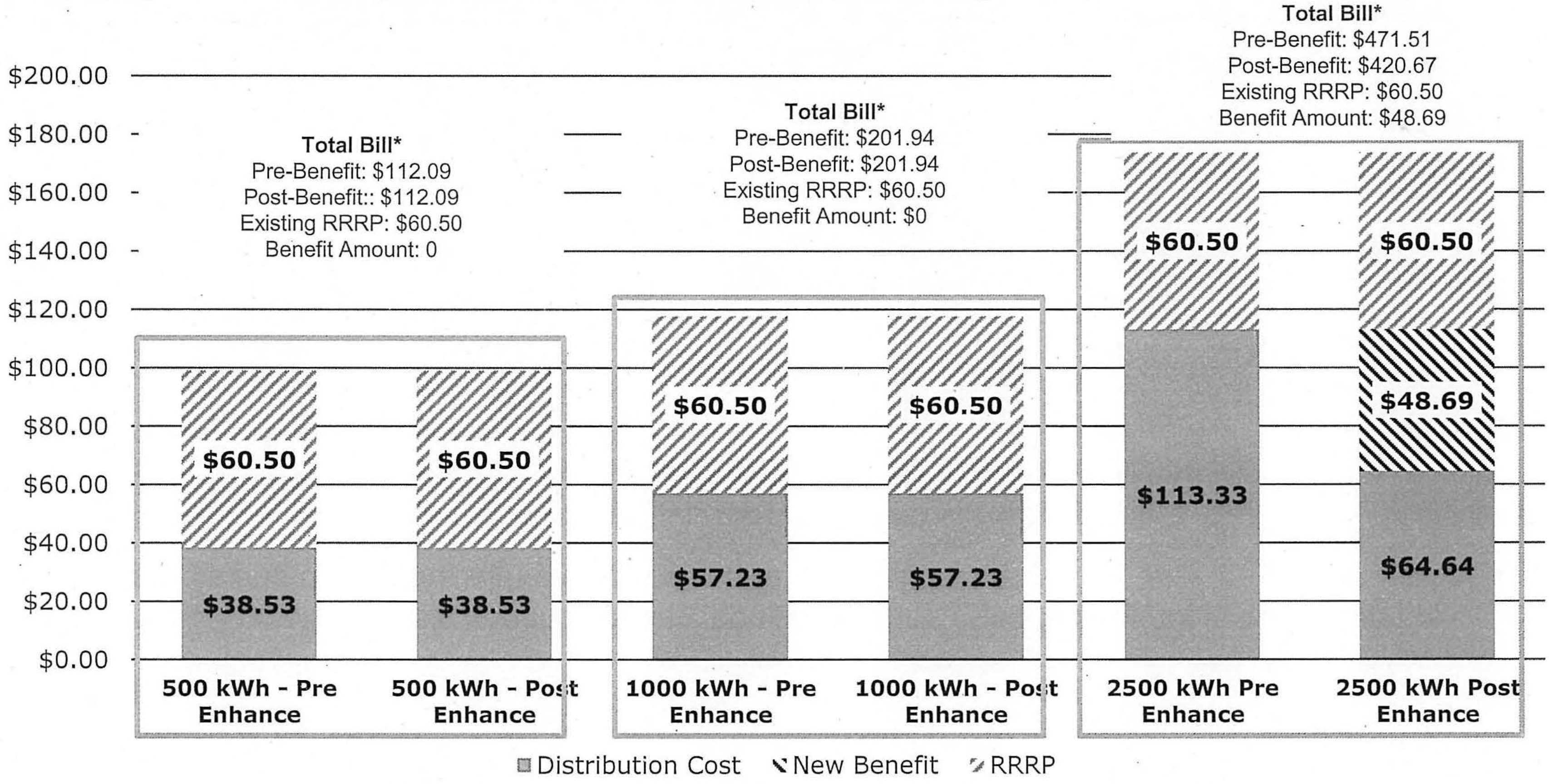
2a. RRRP Enhancement – Hydro One Mid-Density (R1) Ratepayer Impacts

- Under this option, R1 customers will not pay more than $55.70 for distribution service. Customers with costs below this threshold experience no change.



2a. RRRP Enhancement – Hydro One Low-Density (R2) Ratepayer Impacts

- Under this option, R2 customers will not pay more than $64.64, after accounting for the original $60.50 RRRP subsidy. Customers with costs below this threshold experience no change.



Note: Rates are 2017

Note:R2 at 500Kwh has costs that align with those of other LDCs like Toronto Hydro

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

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. These benefits could range from $67 to $113/month.
    - The Ministry is also considering options to support a “Delivery” line credit for Indigenous consumers. This would cost ~$18 million/year 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

- 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.
- 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

2b. OESP Expansion – Considerations

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 – Home Assistance Program Enhancement

- Existing low-income programs delivered by LDCs and IESO help qualified residential customers and social and/or assisted housing providers improve their energy efficiency.
  - Programs include the Home Assistance Program and the Retrofit Program (Social Housing stream).
  - $500 million is planned under the Climate Change Action Plan (CCAP) to retrofit social housing.
- ENERGY is currently working with IESO to explore options to enhance and/or expand the existing Home Assistance Program or residential customers:
  - Participants could receive incentives for improved weatherization measures, appliances and lighting controls (e.g., new or upgraded furnace and central AC; windows/doors; washer/dryers, heat pumps (for electrically-heated residential customers).
  - The incremental funds would enable deeper measures and reach additional customers.
  - The new program would be delivered through LDCs and/or IESO and could include education and awareness initiatives.
- The budget estimate below is illustrative and reflects a doubling of the 2015 spending for the Home Assistance Program, which was $20 million.

Calendar Year	**2017**	**2018**	**2019**	**2020**	**2021***	**2022***
Current Budget ($Million)	10	10	10	10	-	-
Fiscal Year	**2017/ 18**	**2018/19**	**2019/20**	**2020/21**		
Proposed New Budget ($ Million)	22.5	40	40	32.5	-	-

***Note:** The Conservation First Framework extends to 2020.

2c. Establishing a New LDC Affordability Fund

- Some electricity customers who struggle to pay their utility bills do not meet the definition of a low-income household and therefore are not eligible for the Home Assistance Program.

- Establishing an "Affordability Fund" for LDCs could provide a means to help struggling customers who do not qualify for low income programs and cannot upgrade their homes without financial assistance.
  - Over time the Fund could help these customers get back on track with their bills and save on disconnection costs.
  - The Fund would be targeted to customers on an as-needed basis (vs. marketed as an open-intake program).

- ENERGY is exploring the potential to establish an Affordability Fund, with funding criteria and reporting requirements.
  - To allow for funds to flow in 2017/18, ENERGY would sign a Transfer Payment Agreement (TPA) with a qualified third party/ies to administer the Fund.
  - LDCs would apply for funding and redistribute support to those customers that meet the targeted eligibility criteria.

- Recipients could receive measures similar to those available in the Home Assistance Program (weatherization, energy efficient appliances and lighting controls).
  - As an illustration, with $200 million, the estimated reach of the fund could be 15,000 to 65,000 households, depending on measures and uptake.

3. OEB – Red-Tape Reductions / LDC Efficiencies and Rates

Leveraging the OEB

- 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.
- The OEB, through the Renewed Regulatory Framework for Energy (RRFE), has since 2012 attempted to move the distribution sector towards a performance/outcomes-based regulatory framework.
  - While new reporting requirements such as the LDC performance scorecard are positive developments, RRFE does not tie these system performance expectations to LDC financial performance.
- Performance-based options have the potential to indirectly incent consolidation (in a manner that returns benefits to consumers), improve customer experience, and potentially reduce Return On Equity (ROE) in an equitable manner in the event performance expectations are not met.
- Encouraging shared partnerships on services between utilities will help reduce costs in the back end and encourage further innovation for small to medium sized utilities.

Opportunities

- ENERGY could help promote or accelerate these efforts by asking the OEB to look at opportunities to further drive LDC efficiencies and productivity.
- In parallel, the OEB could be instructed to review business cases behind its own regulatory requirements to reduce "red tape" and eliminate costs that LDCs indicate are creating pressures on operating expenses.
- This could be done through the Minister's letter, 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.

3. OEB – LDC Efficiencies and Rates (Performance Incentives) (cont'd)

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.

4. 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.

5. 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.

<u>Considerations</u>

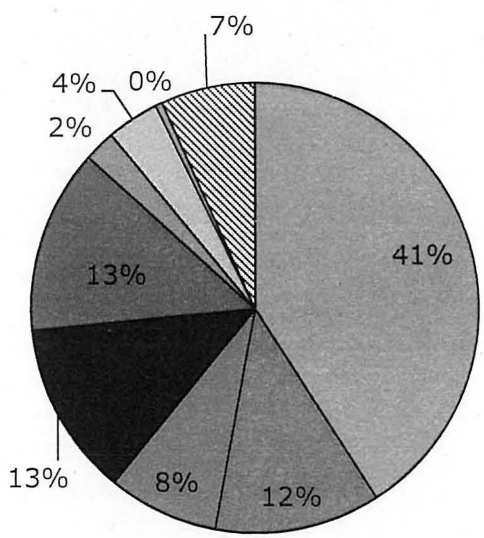
- Changes related to IESO's Market Renewal initiatives, reflected in HOEP and uplifts, are estimated to save up to $300 million per year, starting in 2021, leading to a reduction of:
  - About $1/month or less than 1% at current retail prices for a typical residential bill; and
  - About $1.30/MWh at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

Appendix

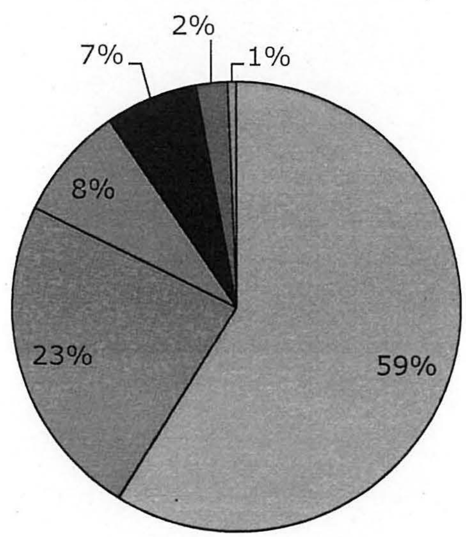
GA Smoothing – Cost Breakout

- 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)
Nuclear	5,053	91
Hydro	1,473	36
Natural Gas	985	13
Wind	1,552	10
Solar	1,630	3
Biomass, Landfill and Byproduct	278	1
Conservation	467	
IEI Program	60	
OEFC*	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.

GA Smoothing – Considerations (*Accounting Treatment: Does Province Control Entity?)*

Defining the Government Reporting Entity

- The government reporting entity should comprise government components and those organizations that are controlled by the government.

Determining Whether Control Exists

- Control is the power to govern the financial and operating policies of another organization with expected benefits or the risk of loss to the government from the other organization's activities.
- Whether a government controls an organization is a question of fact that must be determined by reference to the definition of control described in the prior paragraph and the particular circumstances of each case.
- Requires the application of professional judgment based on the definition of control and the substance of the relationship.
- It is the preponderance of evidence that would be considered in assessing whether a government controls an organization.

GA Smoothing – Considerations (*Accounting Treatment: Does Province Control Entity?*) (cont'd)

Indicators of Control

- There are certain indicators that provide more persuasive evidence of control:
  - Government has the power to unilaterally appoint or remove a majority of the members of the governing body of the organization;
  - Government has ongoing access to the assets of the organization, has the ability to direct the ongoing use of those assets, or has ongoing responsibility for losses;
  - Government holds the majority of the voting shares or a "golden share" 1(1) that confers the power to govern the financial and operating policies of the organization; and
  - Government has the unilateral power to dissolve the organization and thereby access its assets and become responsible for its obligations.

- Other indicators that may provide evidence of control exist when the government has the power to:
  - Provide significant input into the appointment of members of the governing body of the organization;
  - Appoint or remove the CEO or other key personnel;
  - Establish or amend the mission or mandate of the organization;
  - Approve the business plans or budgets for the organization and require amendments;
  - Establish borrowing or investment limits or restrict the organization's investments;
  - Restrict the revenue-generating capacity of the organization, notably the sources of revenue; and
  - Establish or amend the policies that the organization uses to manage, such as those relating to accounting, personnel, compensation, collective bargaining or deployment of resources.

Overview of RRRP Enhancement – Options

	Program Envelope for H1 ($M)*	Monthly Rebate for R2:low density consumers (+/- from status quo)	Monthly Rebate for R1: medium-density customers	Monthly cost to ratepayers**
(Status Quo) RRRP program for R1 and R2 customers of Hydro One (as of January 2017)	$242M	$60.50/month	$0	$1.58/month
(1) Accelerates move to fixed distribution rates for those customers expected to see a reduction in costs.* **	$306-$332M	Distribution costs capped at $64.64/month. Benefit begins at 1,200kWh/month	Distribution costs capped at $55.70. Benefit begins at 955kWh/month.	$2.07/month
(2) Increase total RRRP envelope to reduce R2 and R1 distribution costs at 1000kWh/month to Algoma Power costs at 1000kWh/month	$292M	$66.61/month (+$6.11/month)	$4.91/month	$1.90/month
(3) Change RRRP program to a volumetric-based tiered benefit program where rebate will be dependent on customer consumption levels				
(3a) • Assume total RRRP program envelope of $300M and distribute to R2 & R1 based on tiered-benefit levels. • Tiered-benefit levels: divide customer base into 3 equal buckets. Allocate $300M to each bucket in proportion to contribution of H1 distribution revenues. • Assume fixed current $60.50 rebate no longer applies equally to all R2 customers.	$300M	750kWh or less: $37.65 (-$22.85) 750 to 1,200 kWh: $44.74 (-$15.76) 1,200 kWh or more: $60.69 (+$0.49)	600Kwh or less: $16.05 600kwh to 1,000Kwh: $19.22 1,000kwh or more: $25.67	$1.90/month
(3b) • Expand RRRP program envelope and distribute to both R2 & R1 customers based on tiered-benefit levels. • Tiered-benefit levels determined in same manner as 3(a). • Assume fixed current $60.50 still applies to all R2 customers	$542M	750kWh or less: $81.66 (+$21.16) 750kwh to 1,200 kWh:$91.90 (+$31.40) 1,200 kWh or more: $114.95 (+$54.45)	600 kWh or less: $23.19 600kwh to 1,000 kWh: $27.76 1,000 kWh or more: $37.09	$3.20/month

*All option costs are inclusive of status quo RRRP, except 3(a) which assumes a phaseout of the program.
**Only if left on ratebase. Will increase based on yearly expansion.
***Based on Hydro One estimates. Consumer benefit is total costs subtract the cap amount.
Note: figures do not include ~$50M in RRRP costs currently supporting Algoma Power and Hydro One Remotes

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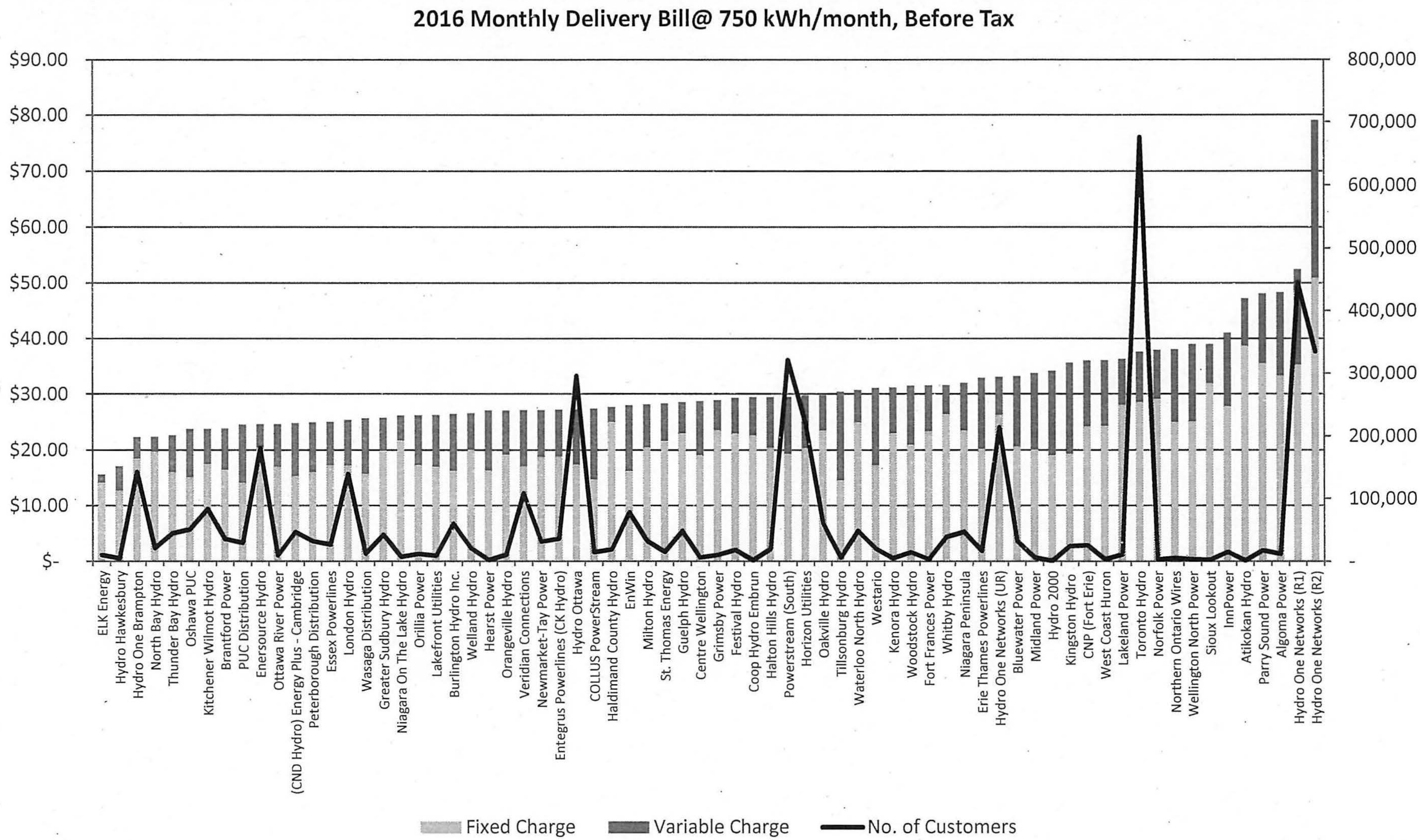
Wide Variation in Delivery Rates Across the Province



* Hydro One customer numbers are for 2016 and divided by rate class. Hydro One R2 does not reflect RRRP enhancement.

All RRRP Options – Fiscal Considerations

Ratepayer Impacts

- Some consumers with low consumption may still have proportional higher distribution rates. These customers will experience bill pressures both from the transition to fixed rates and from expected general rate increases (for which they are responsible for an increasing proportion).
- Hydro One distribution rates are expected to climb in coming years. The projected 2017 fixed rates of $64.64 (R2) and $55.70 (R1) will rise through the transition period. Therefore customers who receive a benefit will still experience bill increases.

Fiscal Impacts

- Having the original RRRP subsidy remain on the rate-base allows for program expansion from the fiscal plan while avoiding an additional $242M tax-base impact.
- Hydro One is expected to submit its cost of service application for 2018 and beyond (3-5 years) in spring 2017. The rate increases requested in this application could potentially increase the proposed fixed rate significantly, which would have significant impact on fiscal requirements and ratepayer impacts.
- Cost for Hydro One to implement and to upgrade customer billing systems is likely material. Those costs would ultimately be passed back to the customers of those LDCs.
- The Ministry will need to consider how consumption thresholds and/or benefit levels rise alongside the expected rise in distribution rates.
- There is a high risk of entrenching external subsidies, as there is no clear path to transition away from subsidies and toward a more sustainable, cost-based rate framework.

All RRRP Options – Implementation Considerations

- LDCs would track credit variances in a variance account and settle amounts with the IESO, which receives taxpayer funding from ENERGY/MoF in the same manner as the 8% rebate happens today.
  - While this new program would build on exiting transfer payment protocols in use under the ORECA, it would be complex for Hydro On to implement, as CIS upgrades are likely needed.
  - Depending on the option chose, OEB estimates that the implementation would take at least 6 months or more, following finalized regulations, given need to change customer billing systems and determine settlement procedures.
- RRRP focuses on ameliorating differences in distribution costs, not the entire Delivery line of the residential bill which also includes transmission and line loss costs.
- Eligibility for RRRP is currently determined by LDC density levels. Hydro One R1 has similar density levels to some other LDCs (e.g., InnPower). Thus if the intention is to limit expansion to just Hydro One R1, a new eligibility criteria would have to be developed (legal and regulatory risks would need to be explored).
- New legislation would be required to establish this program. Legal and regulatory risks (particularly with regards to legal authority and to the Ontario Energy Board's role in setting rates and incenting efficiencies) require further analysis.
  - Some options may impact OEB rate-setting processes and create disincentives towards Hydro One productivity and performance improvements.
- Providing a tax-based subsidy outside of exiting rate setting mechanism reduces incentives for customers and distributors to engage on operating costs and capital planning.
- The development of an appropriate program can be initiated through a letter to the Ontario Energy Board via s. 35 of the *Ontario Energy Board Act, 1998.*

OEB – LDC Efficiencies and Rates (Performance Incentives)

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. Ex: SAIDI/SAIFI; OM&A per customer	• 1-2% of revenue requirement could be recycled back to customers. • Performance penalties would be real, periodic on-bill $ reductions. • 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. • 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. • 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. • 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

LDC Distribution Rate Changes (2006 vs 2016)

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.

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	41.2%
Hydro One R2 (Low Density)	$44.65	$76.14	[illegible]