EXECUTIVE SUMMARY

This Exhibit describes the scope of Hydro One's Application and its proposed Custom IR approach to setting Distribution Rates for the period 2018 to 2022. It also provides an overview of Hydro One's Distribution business and explains how Hydro One developed the business plan that underpins this Application, in consideration of customer needs and preferences, the condition of the Distribution System, and resulting bill impacts.

Also included in this Exhibit is a Summary of the Application. The Exhibit addresses the requirements of Sections 2.1.2 and 2.1.5 in Chapter 2 of the Ontario Energy Board's (the "OEB") *Filing Requirements for Electricity Distribution Rate Applications*, issued on July 14, 2016.

1. SCOPE AND KEY CONSIDERATIONS OF THIS APPLICATION

Hydro One Networks Inc. ("Hydro One") is applying for an Order approving its Distribution revenue requirement, cost allocation and rates as determined by its Custom IR approach for the period 2018 to 2022 (in this Exhibit, the "Term") under the assigned docket number EB-2017-0049.

In this Application, Hydro One is requesting the OEB's approval of the following:

- The *rates revenue requirement* of $1,446.3 million for 2018, the underlying calculation of which is provided in Section 5.1 of this Exhibit;
- The *proposed Custom IR rate model* to determine the revenue requirements for each subsequent year of the Term, as described in Section 2 of this Exhibit, and further described in Exhibit A, Tab 3, Schedule 2;
- The OEB's mandatory *scorecard* for electricity distributors (the "Electricity Distributor Scorecard") and the proposed supplemental scorecard (the "Distribution

OEB Scorecard"), as set out in Exhibit A, Tab 5, Schedule 1 and Section 1.4 of Exhibit B1, Tab 1, Schedule 1, respectively;

- The continuation or creation of the various *regulatory accounts* discussed in Section 10 of this Exhibit;
- The *disposition of regulatory accounts* with a forecast net debit balance of $30.9 million effective January 1, 2018, to be collected over a five-year period, at $6.2 million per year;
- The proposed *specific service charges* detailed in Exhibit H1, Tab 2, Schedule 3;
- The creation of *new customer classes* discussed in Section 9 of this Exhibit; and
- *2018 rate schedules*, including terms and conditions of service, effective January 1, 2018, as set out in Exhibit H1, Tab 2, Schedule 1, which incorporate Hydro One Distribution's proposed retail transmission service charge.

The requested 2018 revenue requirement reflects an increase of 1.9% over 2017 OEB-approved levels. The increase is largely attributable to rate base growth including associated increases in depreciation, return on capital and income tax expenses as described in Exhibit E1, Tab 1, Schedule 1. The increase is partially offset by a lower cost of debt and lower OM&A expense. After adjustment for a reduced load forecast (3.0%), the resulting average impact on distribution rates is an increase of 4.9% in 2018, and an average of 3.5% per annum over the Term.

In preparing this Application, Hydro One was acutely aware of the impact on customer rates arising from investments in the electricity system, an impact that is further exacerbated by a reduced load forecast, and of the clear preference of its customers for low electricity costs. As a result, the Application reflects the level of capital investment required to avoid degradation in overall system asset condition, to meet regulatory requirements and maintain current reliability levels. Further, OM&A reflects efficiency improvements and cost reductions to control the extent to which OM&A contributes to the increase in customer rates. The proposed level of 2018 OM&A reflects a small decline from 2017 OEB-approved levels. The planning process followed by Hydro One also resulted in significant reductions in investments in 2018, to mitigate customer rate

impacts in that year. As a result, the Application is responsive to Hydro One's customers' needs and preferences.

Investments during the Term include:

- maintenance of the population of poles and distribution stations at materially the same condition level, without significant improvement in overall condition;
- investments in lines sustainment and lifecycle optimization;
- investments to comply with regulatory requirements such as PCB line equipment replacements;
- investment in an Integrated System Operations Centre, which replaces the existing backup power system control and telecommunication centres; and
- later in the term, some investments to begin replacement of smart meters that are reaching end-of-life.

The components of the increased revenue requirement, and their individual contributions, are noted in Table 1 below. These components comprise certain factors that impact 2018 rates, but which were outside of Hydro One's immediate control in developing its 2018-2022 distribution business plan (the "Dx Business Plan"). They include legacy rate base (resulting from necessary prior-year in-service additions), the need to clear regulatory deferral and variance accounts, and planned 2018 in-service additions that are to a large extent non-discretionary (e.g., accommodating the connection of load and generation customers, responding to storms damage and trouble calls, and complying with regulations and other requirements). As a result, to mitigate these effects, Hydro One has planned very few incremental system improvement or end-of-life capital investments in 2018.

Table 1: Impact of Individual Components on Revenue Requirement

Description	2018 vs. 2017 OEB-approved (M$)	2018 vs. 2017 OEB-approved (%)
OM&A	(8.2)	(0.5)
Rate Base Growth	31.4	2.2
Cost of debt	(3.7)	(0.3)
Tax	12.8	0.9
Impact on Revenue Requirement	**32.3**	**2.3**
External Revenue	(0.9)	(0.1)
Regulatory Deferral and Variance Accounts Disposition	(4.9)	(0.3)
Total Change	**26.5**	**1.9**

Exhibit Reference: E1-1-1.

In a formal Customer Engagement that it conducted in the summer of 2016, Hydro One received customer feedback that Hydro One must control costs better and demonstrate greater fiscal management and operational efficiency before considering rate increases. Customers also stated that electricity costs are their primary concern, with system reliability being a second priority.

This Application reflects these views, concerns and customers' needs and preferences regarding rates and reliability. In developing the Dx Business Plan, following the Customer Engagement, Hydro One studied three alternative investment plans, differentiated by varying outcomes, spending profiles, and rate impacts. The plan that informs this Application is a modified version of one of those three original investment plans. It is designed to limit rate impacts while still addressing minimum system needs by focusing investment on deteriorated infrastructure and by managing and controlling costs through investments that maintain reliability, but are insufficient to improve the overall reliability of the aging distribution system.

This Application reflects a reduction in 2018 capital expenditures from OEB-approved 2017 levels, and 2018 OM&A that is slightly lower than the OEB-approved level for 2017. Specifically, Hydro One's capital expenditures are reduced by approximately

4.2%, and OM&A expenditures are lower by approximately 1.4%. This is due to investment pacing decisions, reduced pension costs, and productivity stretch targets that management has adopted. Hydro One has developed several approaches and initiatives to manage costs within its control. This includes greater use of benchmarking studies to inform the Distribution System Plan ("DSP") and to help manage resources and costs incurred throughout the Term. (See Section 1.6 of the DSP for further discussion.) The Application also describes Hydro One's focus on performance management and the measures that the Company is adopting to ensure that targets are met over the Term. A detailed discussion of performance management and measures is found in Section 1.4 of the DSP.

In developing the revenue requirement for the period beyond 2018, Hydro One originally adopted the highest stretch factor applicable under the OEB's existing incentive regulation regime. Hydro One did so after reviewing the results of a total cost benchmarking study (completed by Power Systems Engineering Inc.) for the period 2013 to 2015. The study was refreshed, using 2016 audited actuals. Based on the results, Hydro One has updated its proposed stretch factor reflecting an improvement in its total cost performance.

The estimated increase in the total bill for Hydro One General Service Energy customers consuming 2000 kWh/month is 1.8% in 2018, and the average annual estimated total bill increase over the Term is 1.2%. For Hydro One medium density residential customers consuming 750 kWh/month, the estimated increase is 2.9% in 2018 and the average annual estimated total bill increase over the Term is 1.8%. Bill impacts are addressed in greater detail in Section 11 of this Exhibit.

2. THE CUSTOM IR PROPOSAL

Hydro One's Application is based on a Custom Incentive Rate-Setting approach for a five-year period. The revenue requirement for the first year (2018) is determined using a cost of service, forward test year approach. To establish the annual revenue requirements from 2019 to 2022, Hydro One is proposing a Revenue Cap IR, whereby the revenue for the test year t+1 is equal to the revenue in year t adjusted annually by the revenue cap index (RCI).

The custom RCI is expressed as:

$$RCI = I - X + C$$

Where:

- "I" is the inflation factor, as determined annually by the OEB.
- "X" is the productivity factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.
- "C" is Hydro One's Custom Capital Factor, determined to recover the incremental revenue in each test year necessary to support Hydro One's proposed Distribution System Plan, beyond the amount of revenue recovered in rates.

A detailed discussion of these components is found in Exhibit A, Tab 3, Schedule 2.

The proposed Revenue Cap IR model has several advantages over a Price Cap IR model. Specifically, the Revenue Cap IR:

- provides the needed flexibility to introduce new rate classes in 2021 to fully integrate Norfolk Power Distribution Inc., Haldimand County Hydro Inc., and Woodstock Hydro Services Inc. (together the "Acquired Utilities"), as described in Exhibit A, Tab 7, Schedule 1;

- permits the continued transition to fully-fixed rates for residential customers (EB-2014-0416);
- provides adequate flexibility to reset customer rates should the OEB proceed with the elimination of the seasonal rate class over the Term (EB-2013-0416/EB-2016-0315);
- provides adequate flexibility to reset customer rates as the OEB advances its initiative relating to rate design for commercial and industrial electricity customers (EB-2015-0043); and
- allows Hydro One to update its billing determinants and cost of capital parameters in 2021 to reflect estimated changes in the industry and load forecast over the Term, consistent with its proposal to integrate the Acquired Utilities.

A summary of the capital- and OM&A-related revenue requirement components is set out in Table 2.

Table 2: Summary of Revenue Requirement Components ($ Million)

Line		Reference	2018	2019	2020	2021	2022
1	Rate Base	D1-1-1	7,671.6	8,049.8	8,477.9	9,036.5	9,436.6
2	Return on Debt	E1-1-1	191.6	201.1	211.8	225.7	235.7
3	Return on Equity	E1-1-1	269.4	282.7	297.7	317.4	331.4
4	Depreciation	C1-6-2	392.6	413.5	428.6	448.1	463.0
5	Income Taxes	C1-7-2	61.5	64.7	66.4	72.7	72.7
6	Capital Related Revenue Requirement		915.1	962.0	1,004.5	1,063.9	1,102.8
7	Less Productivity Factor (0.45%)			(4.3)	(4.5)	(4.8)	(5.0)
8	**Total Capital Related Revenue Requirement**		**915.1**	**957.7**	**1,000.0**	**1,059.1**	**1,097.8**
9	OM&A	C1-1-1	584.8	593.3	601.9	610.6	630.4
10	Integration of Acquired Utilities	A-7-1				10.7	
11	**Total Revenue Requirement**		**1,499.9**	**1,551.0**	**1,601.9**	**1,680.4**	**1,728.2**
12	Increase in Capital Related Revenue Requirement			42.6	42.3	59.1	38.8
13	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			2.84%	2.73%	3.69%	2.31%
14	Less Capital Related Revenue Requirement in I-X			0.88%	0.90%	0.91%	0.91%
15	**Capital Factor**			**1.96%**	**1.83%**	**2.78%**	**1.39%**

Exhibit Reference: A-3-2

To align Hydro One's business interests with those of customers and provide an additional element of protection for customers, Hydro One is also proposing the following features:

- An earnings sharing mechanism that will permit customers to share 50% of any earnings that exceed the regulatory ROE by more than 100 basis points in any year of the Term;
- A capital in-service variance account to track the cumulative difference over the Term between: (a) the revenue requirement associated with actual in-service capital additions during a rate year; and (b) the revenue requirement associated with the OEB-approved forecast for in-service capital additions for that year; for any capital in-service additions that are 98% or lower than the OEB- approved level; and
- Z-factor and off-ramp mechanisms that apply OEB-approved criteria.

Hydro One's proposed custom IR components, therefore, contain both OEB-approved components and other mechanisms that are designed to align the utility's and the customers' interests.

The other rate adjustment during the Term will address the integration of the Acquired Utilities. As outlined in Exhibit A, Tab 7, Schedule 1, Hydro One proposes to integrate the Acquired Utilities effective January 1, 2021. As set out in Exhibit G1, Tab 2, Schedule 1, Hydro One will introduce six new rate classes at that time. The OM&A costs associated with the Acquired Utilities will be incorporated into the revenue requirement for 2021, and the capital costs associated with the Acquired Utilities will also be incorporated into the Custom Capital Factor at that time.

3. OVERVIEW OF THE HYDRO ONE DISTRIBUTION BUSINESS

Hydro One serves approximately 1.3 million distribution customers across a vast service area that is 99% rural and through a system that is largely radial in design. This design is cost-effective for Hydro One's service area, where the average customer density is fewer than three customers per square kilometre, although the lack of redundancy does have reliability impacts on customers. Most of Hydro One's distribution system was built in the 1950s and the 1960s, and many assets are approaching or are beyond their expected

service lives, resulting in an ongoing need to replace or refurbish assets at an increasing rate if system reliability and safety are to be maintained. Any material improvement in reliability or system condition requires significantly more investment, which would impact customer bills in a manner inconsistent with the feedback that Hydro One received in its customer engagement process. An overview of Hydro One's distribution system and a detailed discussion of its key components are provided in Sections 2.2 and 2.3 of the DSP in Exhibit B1, Tab 1, Schedule 1.

Hydro One was established in 1999 as a company wholly-owned by the Province of Ontario. In 2015, Hydro One's parent company transitioned from being solely government-owned to being publicly-traded, and a new Board of Directors was appointed to enhance the customer-centric, commercial orientation of the organization. Specifically, management and the new Board of Directors intend to increase Hydro One's focus on customers, create greater corporate accountability for performance outcomes and drive continuous company-wide improvements in efficiency and productivity.

4. DEVELOPMENT OF HYDRO ONE'S DISTRIBUTION BUSINESS PLAN

This Section provides an overview of the development of the Dx Business Plan, which underpins Hydro One's Application and especially the Distribution System Plan, which is set out in Exhibit B1, Tab 1, Schedule 1 of this Application.

The Dx Business Plan reflects Hydro One's core values and business objectives and attempts to align three competing but equally important factors: (i) customer needs and preferences; (ii) responsible stewardship of the distribution system; and (iii) customer bill impacts. The Dx Business Plan has been shaped by: (i) Hydro One's commitment to reduce costs and increase productivity and efficiency before asking customers to pay more; (ii) directing investment to address specifically identified customer needs and

preferences; (iii) reducing or deferring investment where trade-offs with respect to reliability can reasonably be justified by lower rates; and (iv) evaluating the resulting rates profile for the Term in the context of the customer feedback referred to in Section 1.3 of the DSP.

The Dx Business Plan seeks to meet customers' needs regarding reliability and power quality and responsible asset management in a manner that controls costs, recognizing the sensitivities that customers have to the total price of power. The Dx Business Plan includes significant productivity initiatives, cost reduction initiatives, and the minimum level of capital required to responsibly manage the electricity distribution system.

The Dx Business Plan is provided as Attachment 1 to this Exhibit, and excerpts from Hydro One's consolidated business plan on strategy, customer, and common corporate costs are provided in Attachment 2.

4.1 CORE VALUES AND BUSINESS OBJECTIVES

Management expects Hydro One to be a best-in-class, customer-centric commercial utility that is easy to do business with, has a presence in the communities it serves, and consistently meets the needs and preferences of its customers.

Hydro One's core values are:

- caring for customers;
- maintaining a safe workplace;
- operating as one company;
- being people-powered; and
- executing with excellence.

Hydro One's executive leadership and Board of Directors are focused on delivering the service expected by customers while managing costs and improving operational

efficiencies. The ability to measure and track Hydro One's performance is essential to this vision.

Table 3 describes Hydro One's business objectives and the metrics that Hydro One uses to measure its progress, and shows how these business objectives align with the OEB's *Renewed Regulatory Framework* ("RRF").

Table 3: Alignment of RRF Outcomes with Hydro One's Business Objectives and Performance Measures

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Customer Focus Services are provided in a manner that responds to identified customer preferences	Consistently improve customer satisfaction	• Handling Unplanned Outages Satisfaction % • Call Centre Customer Satisfaction % • My Account Customer Satisfaction % • New Residential/Small Business Services Connected on Time • Scheduled Appointments Met On Time • Telephone Calls Answered On Time • First Contact Resolution • Billing Accuracy • Customer Satisfaction Survey Results
	Engage with our customers consistently and proactively	• Used to inform outcomes
	Ensure our investment plan reflects our customers' needs and desired outcomes	• Used to inform outcomes

RRF Outcomes	Hydro One Business Objectives	Performance Measures
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives	Actively control and lower costs through OM&A and capital efficiencies	• Total Cost per Customer • Total Cost per km • OM&A per Customer • OM&A per km of Line • Pole Replacement –Cost per Unit • Vegetation Management – Cost per km Line Clearing • Station Refurbishments – Cost per MVA
	Achieve and maintain employee engagement	• Drives company culture leading to improved Operational Effectiveness
	Drive towards achieving an injury - free workplace for employees and the public	• Drives company culture leading to improved Operational Effectiveness • Level of Public Awareness • Level of Compliance with Reg. 22/04 • Number of General Public Incidents
	Provide reliability consistent with customer requirements	• Average Number of Times that Power to a Customer is Interrupted • Average Number of Hours that Power to a Customer is Interrupted. • Rural and Urban SAIFI • Rural and Urban SAIDI • Large Customer Interruption Frequency • Number of Substation Caused Interruptions • Number of Vegetation Caused Interruptions • Number of Line Equipment Caused Interruptions • In-Service Additions (Capital Work Program Completion)
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements	Ensure compliance with all codes, standards, and regulations	• Monitored by the applicable business unit(s)
	Partner in the economic success of Ontario	• Monitored by the applicable business unit(s)

RRF Outcomes	Hydro One Business Objectives	Performance Measures
imposed further to Ministerial directives to the Board).	Sustainably manage our environmental footprint	• Net cumulative energy savings • Renewable CIAs completed on time • Micro embedded facilities connected on time
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Achieve the ROE allowed by the OEB	• Current Ratio (Current Assets/Current Liabilities) • Return on Equity (deemed) • Return on Equity (achieved) • Total Debt to Equity

Exhibit Reference: B1-1-1

4.2 CUSTOMER NEEDS AND PREFERENCES

In June and July of 2016, Hydro One undertook a formal customer engagement initiative to obtain customer feedback to inform its planning decisions. The initiative was designed to reach as many customers as possible. Hydro One adopted a comprehensive consultation methodology, which included both qualitative approaches (such as focus groups and workshops) and quantitative approaches (such as surveys and online workbooks). The methodology and process are detailed in Section 1.3 of the DSP.

Customers were presented with three illustrative investment scenarios. Each scenario was differentiated by varying OM&A and capital investment levels, the corresponding directional impacts on distribution system reliability and customer service, and rate impacts. The engagement materials were tailored for each of Hydro One's five customer segments, namely, Residential and Small Business, Commercial and Industrial, Large Distribution Accounts, Local Distribution Companies, and Distribution-connected Generators.

Based on the results of this formal initiative, and consistent with the customer feedback that Hydro One receives in its day-to-day operations, Hydro One believes that keeping costs as low as possible is the top priority of its customers. Specifically, the results indicated that:[1]

- controlling cost is the top priority for customers;
- customers want to see Hydro One demonstrate greater fiscal management and operational efficiency before considering rate increases;
- maintaining reliable electricity service is consistently second, after cost control, in terms of priority;
- large customers are more concerned than other customers are with reliability and capacity; and
- customers are generally unwilling to accept a rate increase, except in the context of potentially degrading reliability.

4.3 ADDRESSING CUSTOMER FEEDBACK AND STRIKING THE RIGHT BALANCE: "PLAN B MODIFIED"

Following the formal customer engagement initiative, Hydro One developed three alternative candidate investment plans for consideration by its senior leadership team and were reviewed by the Board of Directors. In developing these alternative investment plans, Hydro One assessed the reliability impacts of varying investment levels for rights-of-way (vegetation management), pole replacement and stations. Based on Hydro One's data, these three investment areas are the most significant, predictable drivers of reliability. The alternative investment plans and their estimated projected rate impacts are discussed below:

[1] Attachment 1 of DSP, Ipsos, *Distribution Customer Engagement Report: Development of Distribution Investment Plan August 2016*, pp. 146-147 (Section 1.3).

- Plan A, recommended by the Company's asset managers, would improve reliability and the overall condition of the system, and would result in a 7.1% rate increase in 2018 over 2017 and an average annual rate increase of 3.8% over the Term.
- Plan B, prepared to reflect an option that offered a smaller reliability improvement and marginal improvements in the overall asset condition of the system, would have resulted in a 6.2% rate increase in 2018 over 2017 and an average annual rate increase of 3.5% over the Term.
- Plan C would achieve the lowest possible 2018 rate increase while ensuring continued compliance with Hydro One's regulatory obligations, but would likely result in significantly reduced reliability and further deterioration in the overall condition of the system. Plan C would have resulted in a 5.0% rate increase in 2018 over 2017, and an average annual rate increase of 2.8% over the Term, and was not supported by the Company's asset managers because of the risk to the system.

More detail on Plans A, B, and C is provided in Section 2.4 of the DSP and in Tables 4 and 5 of this Exhibit.

The 2018 rate increases associated with all three of these investment plans reflects some factors that were not entirely within the company's immediate control in developing those plans. Approximately half of the rate increase is caused by changes in the load forecast (due to external factors such as conservation and demand management, and economic conditions) and the settlement of existing regulatory accounts. The large non-controllable component of the rate increase required Hydro One to consider aggressive deferrals of certain investments and significant efficiency initiatives in order to prepare investment plans that are consistent with the outcome of the customer engagement process, which highlighted the importance to customers of keeping cost increases to a minimum.

Hydro One's management, in discussion with the Board of Directors, determined that Plan B would still result in bill impacts that were too high for customers, particularly in 2018 and with the effects of the reduced load forecast. Senior management therefore

challenged planners to continue to investigate a plan that would further mitigate cost increases but still reflect responsible stewardship of the assets and no degradation in reliability over the full Term. In particular, managers were challenged to consider how to mitigate the significant rate increase in 2018.

As a result, an adjusted investment portfolio with a forecasted 2018 rate impact of 5.4%, "Plan B – Modified", was developed that would maintain overall forecasted system reliability at current levels, while continuing to offer discrete power quality and reliability improvements for certain segments of the network. Tables 4 and 5 summarize the assumptions that defined Plans A, B, C and B - Modified.

Table 4: SAIDI Projection for Investment Plan Options

SAIDI[1]:	**Avg. 2013-15: 7.3 hours/year**	**Average Number of Hours that a Customer is Interrupted**					
	Assumptions			**Forecasted Impact on SAIDI [2]**			
	Failure Rate/Impact	**Contribution to SAIDI**	**SAIDI Contribution (based on 2013-15)**	**Plan A**	**Plan B**	**Plan C**	**Plan B-M**
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	3%	0.2	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	4%	0.2	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	23%	1.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	27%	1.8	8%	8%	4%	8%
Estimated Impact to SAIDI				**6%**	**3%**	**(2)%**	**0%**
Forecasted SAIDI (hours)				**6.9**	**7.1**	**7.4**	**7.3**

Exhibit Reference: B1-1-1

1- Excludes force majeure and loss of supply events

2 – These columns reflect the forecasted impact on SAIDI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.

Table 5: SAIFI Projection for Investment Plan Options

SAIFI [1]:	Avg. 2013-15: 2.6 outages/year	Average Number of Times a Customer is Interrupted					
	Assumptions			Forecasted Impact on SAIFI[2]			
	Failure Rate/Impact	Contribution to SAIFI	SAIFI Contribution (based on 2013-15)	Plan A	Plan B	Plan C	Plan B-M
Poles	• 345 outages/year • 180 customers/outage • 10 hours/outage	2%	0.1	20%	15%	(15)%	7%
Stations	• 16 failures (outages) /year • 1200 customers/outage • 24 hours/outage	3%	0.1	14%	5%	(4)%	0%
Other Line Components	• 2070 outages/year • 180 customers/outage • 4 hours/outage	18%	0.5	10%	0%	(10)%	(5%)
Vegetation	• 15,530 outages/year	16%	0.4	8%	8%	4%	8%
Estimated Impact to SAIFI				**4%**	**2%**	**(2)%**	**0%**
Forecasted SAIFI (instances)				**2.5**	**2.6**	**2.6**	**2.6**

Exhibit Reference: B1-1-1

1-Excludes force majeure and loss of supply events

2 – These columns reflect the forecasted impact on SAIFI by the end of 2022. Estimated performance improvement is expressed as a positive value; performance deterioration is expressed as a negative value.

Plan B - Modified included the following adjustments compared to original Plan B:

- A deferral of some 2018 capital spending on wood pole replacements, station refurbishments, component replacements, system capability reinforcement, information technology and facilities and real estate to minimize rate impacts and offset the effects of a reduced load forecast, accepting short-term, small-scale reliability impacts where appropriate;
- The acceleration of productivity initiatives to reduce unit and operational costs and associated rate impacts, which are described in Section 1.5 of the DSP and summarized in Table 6 of this Exhibit;
- To sustain reliability, continued investment in certain System Renewal projects and programs based on asset condition and poor performance; and
- The establishment of OM&A and capital programs to investigate power quality issues, install power quality meters and surge arresters, and improve grounding where needed.

These initiatives reduced the total Term projected capital expenditures by $51 million or approximately 7.5% when compared to original Plan B.

Plan B - Modified reflects an optimized investment portfolio that is designed to maintain current reliability within the proposed envelope for the period 2018 to 2022 by:

- implementing a vegetation management plan that is expected to result in improved reliability, at a spending level consistent with past OEB-approved levels, by using lower cost temporary workers to complete low-skilled work and by better aligning clearing frequency with reliability performance;
- outsourcing cable location work at lower cost;
- replacing poles at a rate that will maintain or slightly reduce by 2022 the population of poles that are in poor condition;
- refurbishing stations at a rate where station condition and reliability will remain stable over the forecast period;
- implementing a worst performing feeder initiative, which will deploy enhanced communication and automation capability to targeted lines to improve reliability by reducing outage duration;
- improved targeting of lines sustainment investments based on performance and focused on the root causes of poor performance;
- targeting OM&A and capital investments to address industrial customer power quality and reliability outliers; and
- ensuring continued compliance with regulatory, environmental and reliability standards.

The investments are described in more detail in Sections 3.1 to 3.8 of the DSP and in Exhibit C1, Tab 1, Schedules 1 to 10.

Hydro One believes that Plan B-Modified is the investment plan that most effectively aligns customer needs and preferences, responsible asset management, and bill impacts. Plan B-Modified maintains system health and reliability at current levels without further degradation, albeit without material improvement to the overall system.

4.4 EXECUTING THE BUSINESS PLAN

Hydro One is focused on delivering service expected by customers while managing costs and improving operational efficiencies, all within the revenue requirement envelope set by the Custom IR approach described in Section 2 of this Exhibit. To ensure Hydro One meets the Dx Business Plan's objectives within the OEB-approved envelope, Hydro One is cultivating a performance management culture that tracks and motivates the desired behaviours and adopting productivity incentives.

4.4.1 PERFORMANCE MANAGEMENT

4.4.1.1 SCORECARDS

As illustrated in Figure 1 below, Hydro One is tracking its performance through (i) the (mandatory) Electricity Distributor Scorecard; (ii) Hydro One's proposed Distribution OEB Scorecard, which is intended to provide greater transparency on outcome measures and areas targeted for improvement; and (iii) its Team Scorecard which is used to award annual short-term incentive payments to management employees.

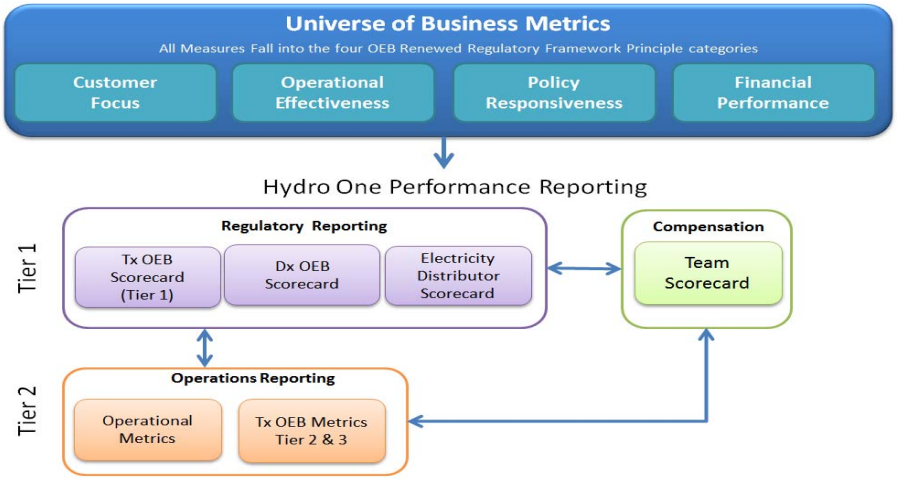

Exhibit Reference: B1-1-1

Figure 1: Performance Reporting Tools

The metrics contained in these scorecards align with the RRF objectives and are expected to drive continuous improvement in asset management, work execution and in customer-oriented performance in support of Hydro One's business objectives. Managers throughout the business are required to include these measures where appropriate in their personal performance goals. As part of Hydro One's performance management system, they are intended to provide transparency to Hydro One's Board of Directors, management, customers, and the OEB, and provide business drivers to ensure that targeted work is completed in an efficient manner, while delivering the stated outcomes for Hydro One's customers.

Exhibit A, Tab 5, Schedule 1 contains a discussion of Hydro One Distribution's performance and targets for the Electricity Distributor Scorecard. Section 1.4 of the DSP addresses the Distribution OEB Scorecard and the targets that Hydro One is proposing for the additional performance metrics described therein. Hydro One's Team Scorecard for 2016 is provided as Attachment 4 to Exhibit C1, Tab 2, Schedule 1.

4.4.1.2 BENCHMARKING

Since its last distribution rates application (EB-2013-0416), Hydro One has commissioned several benchmarking studies as directed by the OEB. The benchmarking reports are included in this Application and discussed in Section 1.6 of the DSP, Exhibit A, Tab 3, Schedule 2, and Exhibit C1, Tab 2, Schedule 1. These studies are focused on: (a) Hydro One Distribution's larger work programs, specifically, its pole replacement, station refurbishment, and vegetation management programs; (b) total compensation costs; and (c) total factor productivity and total cost performance. Hydro One also commissioned an additional benchmarking study focused on information technology spending.

The results of these studies have informed Hydro One's Custom IR approach and its investments and execution strategies. Based on these results, Hydro One continues to evaluate opportunities to further improve its operational efficiency to ensure that it can achieve its RRF-consistent business objectives. For example, Hydro One is investigating the feasibility and cost-benefit analysis of pole refurbishment recommendations, and the development of key performance indicators for station projects related to cost and system impact. More detail on Hydro One's responses to the benchmarking study results and recommendations is provided in Section 1.6 of the DSP.

4.4.2 PRODUCTIVITY INCENTIVES

In its proposed Custom IR model, Hydro One includes an external productivity incentive in the form of a stretch factor of 0.45%. This stretch factor will apply to the entirety of the Hydro One Distribution revenue requirement over the Term. This stretch factor is meant to mitigate the impact of Hydro One's below-average total cost performance relative to its peer group, as evidenced by a total cost benchmarking study performed by Power System Engineering Inc., which is discussed in Exhibit A, Tab 5, Schedule 2. Since filing this Application, Hydro One has updated its total cost performance forecast using 2016 audited actual financial results. The updated forecast shows an improvement in Hydro One's performance relative to its peers, warranting a change in the originally proposed stretch factor of 0.6% to 0.45%.

To ensure that Hydro One executes the Dx Business Plan within the allowed envelope, management has reflected significant efficiency savings targets in the DX Business Plan. These efficiencies are realized in both the capital and OM&A work programs as set out in Table 6. The values in Table 6 are stretch targets that reflect management's commitment to ensuring that all possible efficiencies and cost reductions are achieved before Hydro One asks customers for a rate increase, as expressed by customers during the engagement

process. Specifically, the Company has taken targeted actions to implement productivity improvements as early as 2018, the rebasing year, and intends to achieve further efficiencies over the subsequent four years. While the OEB's RRF provides an incentive for utilities to achieve productivity gains during the Term, such efficiencies ultimately accrue to the benefit of ratepayers at the time of the next rebasing.

Table 6: Detailed Productivity Savings Forecast

$Millions	2018	2019	2020	2021	2022
Capital	25.5	26.8	32.2	33.7	34.5
OM&A	34.8	40.7	43.4	45.8	50.0
Corporate Common	3.2	3.3	3.3	3.3	3.3
Total Savings	**63.5**	**70.8**	**78.9**	**82.8**	**87.8**

Exhibit Reference: B1-1-1

There are additional features of the Custom IR model which align Hydro One's interests with those of its customers in reducing its costs and executing effectively against plan. Two features that provide customers with a measure of protection against excessive utility earnings are the proposed earnings sharing mechanism and asymmetrical capital in-service variance account. These mechanisms are discussed in Section 2 of this Exhibit.

5. SUMMARY OF THE APPLICATION

5.1 REVENUE REQUIREMENT

Table 7 provides a comparative profile of the annual rates revenue requirement build-up from 2017, the last OEB-approved rate year, to 2018, along with references to the Exhibits in the Application that discuss each cost component.

Table 7: Revenue Requirement ($ Millions)

Components	2017[1]	2018	Reference
OM&A	593.0	584.8	Exhibit C1, Tab 1, Schedule1
Depreciation and Amortization	390.2	392.6	Exhibit C1, Tab 6, Schedule 1
Income Taxes	48.7	61.5	Exhibit C1, Tab 7, Schedule 1
Return on Capital	435.8	461.1	Exhibit D1, Tab 2, Schedule 1
Total Revenue Requirement	**1,467.6**	**1,499.9**	Exhibit E2, Tab 1, Schedule 1
Deduct External Revenues and Other	(52.7)	(53.6)	Exhibit E1, Tab 1, Schedule 2
Rates Revenue Requirement	**1,414.9**	**1,446.3**	
Regulatory Deferral and Variance Accounts Disposition	11.1	6.2	Exhibit F1, Tab 2, Schedule 1, Attachment 1
Rates Revenue Requirement (with Deferral and Variance Accounts)	**1,426.0**	**1,452.4**	

Exhibit Reference: E1-1-1

Note 1: The 2017 revenue requirement is from the OEB approved Hydro One Distribution's 2015 to 2017 rate application in EB-2013-0416

The increase in revenue requirement is largely attributable to the impact of rate base growth, as reflected in the increase in depreciation, return on capital, income tax expenses and lower external revenue forecast as described in Exhibit E1, Tab 1, Schedule 2. These are partially offset by a lower cost of debt and lower OM&A costs.

5.1.1 BUDGETING ASSUMPTIONS

For 2018, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.5% and 2.2%, respectively. These assumptions are explained in further detail in Section 2.1.2 of the DSP. Hydro One adopted the US GAAP accounting standard for regulatory purposes, based on the OEB's Decision with Reasons in EB-2011-0268.

5.1.2 LOAD FORECAST SUMMARY

Table 8 sets out Hydro One's 2018-2022 distribution system load forecast, which includes the impact of conservation and demand management and embedded generation.

Table 8: Forecast Energy Deliveries and Customer Count

Year	Energy Delivery Forecast (GWh)	Change (%)	Distribution Customer Count	Change (%)
2018	36,019	(0.6)	1,300,516	0.7
2019	35,680	(0.9)	1,309,216	0.7
2020	35,673	0.0	1,317,967	0.7
2021*	36,363	1.9	1,386,522	5.2
2022*	36,373	0.0	1,395,578	0.7

Exhibit Reference: E1-2-1

** The figures include the impact of integrating Acquired Utilities into Hydro One Distribution. Without this, the GWh delivered would have changed by -0.3% in 2021 and 0% in 2022, and the number of customers would have changed by 0.7% in both 2021 and 2022*

The changes in the energy delivery forecast are distinct from the load impact on rates. The load impact on revenue requirement is a function of peak demand, energy delivery and customer count forecasts by rate class. It reflects changes since the last OEB-approved forecast. As set out in Section 1 of this Exhibit, the reduced load forecast contributes 3.0% of the resulting average increase in distribution rates of 4.9% in 2018.

The forecast was developed using the econometric and end-use approaches described in Exhibit E1, Tab 3, Schedule 1. The forecast base year was corrected for abnormal weather conditions, and growth rates were applied to the normalized base year value. Consistent with the IESO's approach, normal weather data is based on the average weather conditions experienced over the last 31 years.

Relative to 2017 figures, Hydro One forecasts a decrease of 0.6% in its load forecast and an increase of 0.7% over the customer count forecast for 2018. The small decrease in load is mainly due to the impact of conservation and demand management and economic factors.

6. THE DISTRIBUTION SYSTEM PLAN

The basis of Plan B – Modified is Hydro One's DSP, which is provided as Exhibit B1, Tab 1, Schedule 1. The DSP capital expenditure forecast for the Term and for historical years dating back to 2013 is set out in Table 9. A summary line for OM&A expenditures is also provided.

Table 9: Summary of Distribution Capital and OM&A Expenditures ($ Millions)

	Historical (previous plan and actual)											Forecast (planned)				
	2013 [1]	2014 [1]	2015			2016			2017 Bridge [2]			2018 Test	2019 Test	2020 Test	2021 Test	2022 Test
	Plan	Plan	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var					
CATEGORY	$M	$M	$M		%	$M		%	$M		%	$M	$M	$M	$M	$M
System Access	159.5	199.4	183.3	188.1	2.6	182.6	182.7	0.0	176.1	168.3	(4.4)	154.6	157.6	160.9	165.9	170.0
System Renewal	265.7	262.7	250.7	308.4	23.0	265.4	288.3	8.6	285.0	252.2	(11.5)	248.6	318.7	336.7	362.5	451.1
System Service	96.5	85.5	120.1	71.6	(40.4)	103.3	77.4	(25.1)	110.1	66.6	(39.5)	81.8	93.4	85.6	78.8	69.5
General Plant	115.3	99.9	94.8	110.1	16.2	103.3	145.9	41.2	90.1	146.3	62.3	149.0	187.1	135.8	133.4	136.6
Total	637.0	647.5	648.9	678.3	4.5	654.7	694.2	6.0	661.4	633.5	(4.2)	633.9	756.8	719.0	740.7	827.2
System OM&A [3]	610.6	674.5	543.1	572.5	5.4	589.1	562.6	(4.5)	593.0	572.8	(3.4)	584.8	593.3	601.9	621.4	630.4

1) 2013 and 2014 were IRM years and therefore do not have Board-approved capital expenditure figures.

2) Bridge year 2017 is a forecast as of end of 2016

3) System OM&A values include all Operations, Maintenance and Administration expenses.

Exhibit Reference: B1-1-1

6.1 CAPITAL DRIVERS

System Renewal costs are expected to increase by an average of 12.3% annually from 2017 to 2022, reflecting an increase in pole replacements, station refurbishments, line sustainment and life cycle optimization investments to deal with assets at end of life. PCB line equipment replacements increase to meet Environment Canada's December 31, 2025 deadline. In 2021, there is a significant increase in spending as Hydro One begins replacing smart meters that will be at end of life. Higher General Plant investment levels are attributable to an investment in the Integrated System Operations Centre, which replaces the existing backup power system control and telecommunication centres. This investment is described in Investment Summary Document GP18 of the DSP.

Costs associated specifically with renewable energy connections/expansions, smart grid, and regional planning initiatives are summarized in Table 10 below.

Table 10: REG Connections/Expansions, Smart Grid and Regional Planning Investments

DSP ISD#	Investment Name	Total Cost ($M)				
		2018	2019	2020	2021	2022
SA5	Generation Connections	4.1	3.4	3.3	2.9	3.0
SS2	System Upgrades Driven by Load Growth* - Regional Planning Projects only	6.7	11.7	8.4	-	-
SS7	Advanced Distribution System	5.0	0.0	0.0	0.0	0.0
GP25	Leamington TS Capital Contribution	2.2	0.0	0.0	0.0	0.0
GP26	Hanmer TS Capital Contribution	3.4	0.3	0.0	0.0	0.0
GP27	Enfield TS - Capital contribution	2.0	1.0	0.0	0.0	0.0

Exhibit Reference: B1-1-1
*These amounts are included in the investment summary document ("ISD") which covers all investments due to load growth.

Investments have been paced to mitigate rate impacts and offset the effects of a reduced load forecast, which includes managing asset replacement rates and, where appropriate, accepting potentially increased risk, to reduce or defer capital spending requirements. Hydro One's leadership team is actively driving cost reductions and improving productivity to help offset the customer bill impacts of the proposed plan and reduced load forecast.

6.2 OPERATING, MAINTENANCE AND ADMINISTRATION DRIVERS

A summary of forecast OM&A expenses for 2018 is provided in Table 11. More detail is available in Exhibit C1, Tab 1, Schedule 1.

Table 11: Summary of Recoverable Distribution OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	334.5	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	13.2	17.0	11.0
Operations*	29.5	27.6	35.8	31.5	39.4	33.4	37.5	36.7
Customer Care*	209.3	155.4	111.7	118.8	110.9	132.6	111.6	131.6
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	54.4	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	4.7	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**572.8**	**593.0**	**584.8**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*1.8%*	*0.7%*	*2.1%*
% Change (Test vs. 2016 Actual)								*3.9%*

Exhibit Reference: C1-1-1

*Costs associated with the Smart Grid pilot were moved from Customer Care to Operations in 2015.

Hydro One has identified and applied significant productivity and efficiency improvements that have resulted in an OM&A plan that reflects this Application's commitment to the top customer priority of keeping bills as low as possible. In 2018, Hydro One forecasts total OM&A expenditures of $584.8 million. This is an increase of $12.0 million or 2.1% compared with the 2017 forecast expenditures, which is $20.2 million below OEB-approved levels, as shown in Table 12. Despite inflation, the expansion of the Hydro One Distribution system, and expenditures that are required to address the increasing maintenance requirements of a deteriorating distribution system, Hydro One has planned for lower OM&A costs than the last level approved by the OEB in 2017.

Table 12 compares 2017 projected costs to the 2017 OM&A expenditures approved by the OEB in Hydro One's previous distribution application (EB-2013-0416).

Table 12: 2017 OEB-approved versus 2017 Projected OM&A Expenditures

Description	Bridge	
	2017 Forecast	**2017 Approved**
Sustainment	334.5	367.1
Development	13.2	17.0
Operations	33.4	37.5
Customer Service	132.6	111.6
Common Corporate	54.4	54.7
Property Taxes & Rights Payments	4.7	5.0
Total	**572.8**	**593.0**
% Variance	*-3.4%*	

Exhibit Reference: C1-1-1

Hydro One's projected 2017 OM&A costs are $20.2 million lower or 3.4% below OEB-approved levels, mostly due to lower Sustainment expenditures attributable to initiatives

in the vegetation management program (described in Exhibit C1, Tab 1, Schedule 2) and cost reductions that new management has been driving (including a reduction in pension costs) and which are now benefiting the 2018 base year.

Details of Hydro One's corporate staffing and compensation are provided at Exhibit C1, Tab 4, Schedule 1.

7. RATE BASE

Exhibit D1, Tab 1, Schedule 1 provides the details of the derivation of the requested rate base figures for the Term. Table 13 summarizes this request.

Table 13: Distribution Rate Base ($ Millions)

Description	Test				
	2018	2019	2020	2021	2022
Mid-Year Gross Plant	11,908.0	12,500.4	13,179.1	14,048.7	14,757.7
Mid-Year Accumulated Depreciation	(4,561.8)	(4,791.8)	(5,056.0)	(5,396.6)	(5,722.0)
Mid-Year Net Plant	**7,346.2**	**7,708.6**	**8,123.2**	**8,652.2**	**9,035.7**
Cash Working Capital	321.2	335.7	348.3	378.5	395.3
Materials and Supplies Inventory	4.1	5.5	6.5	5.9	5.5
Distribution Rate Base	**7,671.6**	**8,049.8**	**8,477.9**	**9,036.5**	**9,436.6**

Exhibit Reference: D1-1-1

Table 14 compares 2017 forecast rate base to the 2017 rate base approved by the OEB in its Decision on Hydro One's previous distribution application EB-2013-0416.

Table 14: 2017 OEB-approved versus 2017 Bridge Year Forecast Rate Base
($ Millions)

Rate Base Component	2017 Bridge Year (Forecast)	2017 Board-approved	Variance
Mid-Year Gross Plant	11,332.1	11,239.1	92.9
Less: Mid-Year Accumulated Depreciation	(4,298.1)	(4,311.7)	13.6
Mid-Year Net Utility Plant	7,034.0	6,927.4	106.5
Cash Working Capital	310.2	255.7	54.5
Materials & Supply Inventory	4.0	6.8	(2.7)
Total Rate Base	**7,348.2**	**7,189.9**	**158.3**

Exhibit Reference: D1-1-1

Total 2017 rate base is expected to be $158.3 million above the OEB-approved level. This variance of 2.2% is explained by higher in-service additions due to higher than forecast spending on trouble calls and storm damage, as well as joint use and relocation projects. This is partially offset by lower demand for distribution generation connections and more efficient completion of wood pole replacements. In addition, a higher cash working capital requirement also results in higher rate base.

8. COST OF CAPITAL

Table 15 summarizes the cost of capital parameters reflected in the Application, details of which can be found at Exhibit D2, Tab 2, Schedule 1.

Table 15: Cost of Capital

Comparison of Cost of Capital and Rate Base	OEB-approved 2017	2018	Exhibit Reference
Cost of Debt	4.25%	4.16%	D2-2-1
Cost of Equity	8.78%	8.78%	D2-2-1
Total Debt ($ Millions)	4,313.94	4,602.9	D2-2-1
Total Equity ($ Millions)	2,875.96	3,068.6	D2-2-1
Rate Base ($ Millions)	**7,189.89**	**7,671.6**	D2-2-1
Weighted Average Cost of Capital	**6.1%**	**6.0%**	

Exhibit Reference: D2-2-1 and Dx 2015-19 Rate Order Evidence

Hydro One's deemed capital structure for distribution ratemaking purposes is 60% debt and 40% common equity. The 60% deemed debt component comprises 4% short-term debt and 56% long-term debt. For the 2018 rebasing year, Hydro One intends to continue to use the OEB's cost of capital parameters for its deemed short-term debt rate and return on equity, consistent with the OEB's report on cost of capital. Hydro One's forecast 2018 cost of long-term debt is calculated as the weighted average cost rate of embedded debt, new debt issued after the last OEB-approved rate application and forecast debt to be issued in 2017 and 2018.

Hydro One's Application reflects a "placeholder" return on equity of 8.78% for the 2018 test year, based on the cost of capital parameters released by the OEB on October 27, 2016, for rates effective January 1, 2017. Hydro One will update the return on equity and the cost of short-term debt for the purpose of establishing the final revenue requirement for 2018, when those metrics are updated by the OEB later in 2017. Hydro One has applied to also update the cost of capital metrics in 2021 with the integration of the Acquired Utilities.

9. COST ALLOCATION AND RATE DESIGN

Hydro One has followed the OEB's cost allocation and rate design methodologies, with minor changes to address Hydro One's specific circumstances as previously reviewed and approved by the OEB. For the 2021 cost allocation model, Hydro One adopted six new customer classes for the Acquired Utilities and included some adjustment factors within the model to ensure that costs allocated to the six new classes appropriately reflect their cost to serve, as directed by the OEB. Details of these adjustments are discussed in Exhibit G1, Tab 3, Schedule 1.

Hydro One proposes to change only those revenue-to-cost ratios that fall outside the OEB-approved ranges for the Distributed Generation class from 2018 to 2020 and for some of the new Acquired Utilities' rate classes in 2021 and 2022. No changes to fixed/variable splits are proposed except with respect to the move to fully-fixed rates for all residential classes as required by the OEB under proceeding EB-2012-0410, and the transition to new customer classes for general service energy and demand customers of two of the Acquired Utilities. The details of these changes are discussed in Exhibit H1, Tab 1, Schedule 1.

Hydro One proposes bill impact mitigation by gradually phasing-in increases in revenue-to-cost ratios to within the OEB- approved ranges for the Distributed Generation class from 2018 to 2020, the new acquired urban general service energy and demand billed classes in 2021 and 2022, and the new acquired general service demand billed class in 2021. Bill impact mitigation in the form of bill credits will be applied to the streetlight, sentinel light and unmetered scattered load customers of the Acquired Utilities that are transitioning to Hydro One's existing classes. Details of these changes are discussed in Exhibit H1, Tab 1, Schedule 1.

10. DEFERRAL AND VARIANCE ACCOUNTS

Hydro One is seeking approval to continue or establish the following accounts:

- Pension Cost Differential Account;
- Tax Rate Changes Account;
- OEB Cost Differential Account;
- Smart Meter Entity Charge Variance Account;
- Lost Revenue Adjustment Mechanism Variance Account;
- Capital In-Service Additions Variance Account;
- Earning Sharing Mechanism Deferral Account; and
- Bill Impact Mitigation Variance Account.
- Other Post-Employment Benefit ("OPEB") Cost Deferral Account
- Long Term Load Transfer Rate Impact Mitigation Deferral Account

Hydro One is seeking discontinuance of the following regulatory accounts:

- Rural and Remote Rate Protection Variance Account;
- Bill Impact Mitigation Variance Account;
- Revenue Offset Difference Account – Pole Attachment Charge; and
- Revenue Difference Account – Pole Attachment Charge.

Hydro One proposes disposing of its regulatory account balances as at December 31, 2016, plus interest improvement for 2017. Hydro One expects that the OEB's final decision will be based on the audited 2016 year end balances.

It is expected that new distribution rates will be effective and implemented on January 1, 2018 and that the disposition of these accounts will commence on that date. Hydro One's requested recovery in 2018 to 2022 of a total $30.9 million is detailed in Table 16:

Table 16: Hydro One Distribution Regulatory Assets

Disposition of Regulatory Account Balances ($ Millions)		
Description	**US of A Account Ref.**	**Forecast Balance as at Dec. 31, 2017**
Retail Service Variance Accounts*	1550 to 1589	30.7
Retail Cost Variance Accounts	1518/ 1548	0.7
Pension Cost Differential Account	2405	7.9
Tax Rate Changes Account	1592	(4.4)
OEB Cost Differential Account	1508	(1.3)
Smart Meter Entity Charge Variance Account	1551	(0.1)
Revenue Offset Difference Account – Pole Attachment Charge	2405	(2.3)
Bill Impact Mitigation Variance Account	1508	2.4
Microfit Connection Charge Variance Account	1508	(0.8)
Distribution Generation – Other Costs – HONI - Variance Account	1533	0.6
Smart Grid Variance Account	1536	(12.2)
Distribution System Code (DSC) Exemption Deferral Account	1508	9.7
Total Regulatory Accounts for Disposition		**30.9**

Exhibit Reference: F1-2-1
*The disposition of the Retail Settlement Variance Accounts excludes the RSVA – Power – Sub-Account – Global Adjustment. For details see Exhibit F1-1-1.

11. BILL IMPACTS

Table 17 summarizes the 2018 total bill impacts for typical customers in all customer classes. Bill impacts across a range of consumption levels and for customer classes in 2019-2022 are provided in Exhibit H1, Tab 4, Schedule 1.

Table 17: 2018 Total Bill Impacts for Typical/Average Customers

Rate Class	Consumption Level	Monthly Consumption (kWh/kW)	Change in Total Bill ($)	Change in Total Bill (%)
UR	Typical	750	3.71	2.8%
	Average	755	3.72	2.8%
R1	Typical	750	4.40	2.9%
	Average	920	4.64	2.6%
R2	Typical	750	4.37	2.9%
	Average	1152	4.56	2.1%
Seasonal	Average	352	2.68	2.5%
GSe	Typical	2000	7.80	1.8%
	Average	1982	7.74	1.8%
UGe	Typical	2000	4.35	1.2%
	Average	2759	6.03	1.3%
GSd	Average	36104 / 124	170.51	2.4%
UGd	Average	50525 / 135	210.17	2.6%
St Lgt	Average	517	3.23	2.7%
Sen Lgt	Average	71	0.65	3.1%
USL	Average	364	-0.65	-0.7%
DGen	Average	1328 / 13	45.39	10.0%
ST	Average	1601036 / 3091	1,223.27	0.6%

Exhibit Reference: H1-4-1