EB-2017-0049

Energy Probe Compendium

Panel 1: Custom IR Application

The Custom Revenue Cap Index (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.

Although Hydro One is seeking the Board's approval for a Revenue Cap IR and Revenue Cap Index, the overall approach is consistent with the RRF and is similar to the custom Price Cap IR and Price Cap Index methodology approved by the Board in EB-2014-0016, for Toronto Hydro-Electric System Limited.

The proposed Revenue Cap IR has a number of advantages versus a Price Cap IR. The Revenue Cap IR:

- Gives Hydro One 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. ("Norfolk", "Haldimand", and "Woodstock", 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 2018 to 2022 Custom IR 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

Witness: Oded Hubert

- Allows Hydro One to update its billing determinants to reflect estimated changes in the load forecast over the Custom IR term, consistent with its proposal to integrate the Acquired Utilities.

1.1 INFLATION FACTOR

In its December 2013 Report, "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors" (EB-2010-0379), the OEB established a methodology for determining the annual Inflation Factor ("I") to be used in incentive-based rate adjustment mechanisms. The Inflation Factor is based on the weighted sum of:

- 70% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and
- 30% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

Although specifically created for use for incentive rate setting under the Price Cap IR and Annual Index plans, Hydro One proposes to use the same Inflation Factor in its custom Revenue Cap IR and Revenue Cap Index, and to update the Inflation Factor annually for 2019 through 2022, consistent with current Board practice.

The latest Inflation Factor of 1.9% was released by the Board on October 27, 2016 for use in applications for rates effective in 2017. Hydro One has used the 2017 Inflation Factor on a pro-forma basis in its RCI calculation for each of the 2019 to 2022 test years, for the purpose of this Application. The Inflation Factor will be updated annually; when the OEB calculates and makes available the Inflation Factor in each of 2018 to 2021, effective 2019 to 2022, respectively.

Witness: Oded Hubert

Energy Probe Research Foundation Interrogatory # 5

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-02 Page: 3

Interrogatory:

a) Please confirm that the methodology used to establish inflation figures was for Price Cap IR, not Revenue Cap, as Hydro One is proposing.

b) Is Hydro One aware of different inflation methodologies being used for Price Cap applications, as opposed to Revenue Cap?

Response:

a) The inflation factor used by the OEB is designed to provide an industry-specific measure of the growth in the input prices of Ontario distributors. It is calculated as the weighted average of a labour and a non-labour price index which have been determined by the OEB to be reflective of trends in the distribution sector. The derivation of this factor is not tied to a specific rate-setting mechanism in any way. Hydro One does not agree that the OEB's inflation-factor is only applicable for a Price Cap IR framework.

b) Hydro One is not aware of any instances where the derivation of the inflation factor is dependent on the form of the incentive rate-setting mechanism.

Witness: D'ANDREA Frank

The Productivity Factor used in the RCI will not be updated annually over the 2019 to 2022 portion of the Custom IR term.

1.3 CAPITAL FACTOR

The Custom Capital Factor proposed in this Application and used in the RCI is designed to ensure that total revenue resulting from the Custom IR is able to meet Hydro One's specific circumstances arising from the proposed capital investments set out in Hydro One's DSP (Exhibit B1).

The Custom Capital Factor is the percentage change in the Total Revenue Requirement (line 11 of Table 1 below) attributable to new capital investment that is not otherwise recovered from customers. This includes depreciation, return on equity, interest and taxes attributable to new capital investment placed in-service each year of the Custom IR term. The Capital Related Revenue Requirement (line 6) each year is based on the change in rate base.

The calculation of the Custom Capital Factor ("C") is set out in Table 1 below.

The Total Capital Related Revenue Requirement metrics in lines 1 to 8 of Table 1 will be calculated by Hydro One in conjunction with the Draft Rate Order using Board-approved values. These metrics will not change over the term of the Custom IR, with the exception of the applied-for cost of capital update in 2021. The Total Revenue Requirement (line 11 of Table 1) will change annually, as a result of the annual adjustment to the Inflation Factor as it applies to OM&A and costs associated with the integration of the Acquired Utilities (line 10).

Witness: Oded Hubert

The OM&A (line 9) provided for each year in Table 1 is determined based on the 2018 forecast provided in the Application and increased by the Inflation Factor ("I") and reduced by the proposed Productivity Factor ("X"), for a total increase of 1.45% per annum.

Table 1: 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%**

The 2018 Total Revenue Requirement of $1,499.9 million (line 11) is determined based on a forward test year, cost of service approach and is the rebasing year for this Application.

In 2019, the Capital Related Revenue Requirement (line 6) increases to $962.0 million versus $915.1 million in 2018. Hydro One will reduce the Capital Related Revenue Requirement (line 6) by the proposed Productivity Factor of 0.45% or $4.3 million (line 7), such that the Total Capital Related Revenue Requirement is $957.7 million (line 8). The change in Total Capital Related Revenue Requirement (line 8) in 2019 versus 2018 is $42.6 million (line 12). This difference is equal to 2.84% of the 2018 Total Revenue Requirement of $1,499.9 million ($42.6 million divided by $1,499.9 million).

The 2.84% increase in Total Capital Related Revenue Requirement is the total increase in revenue requirement arising from the higher 2019 Capital Related Revenue Requirement (line 6). However, the 2.84% increase must be offset by the increase in revenue requirement that results from the application of the Inflation and Productivity Factors (I - X) of the RCI. This is done by determining the percentage of the Total Capital Related Revenue Requirement (line 8) that is already provided for by the Inflation and Productivity Factors. In 2019, this equals 0.88% ($915.1 million x 1.45% / $1,499.9 million). The net result of 1.96% (2.84% less 0.88%) is the 2019 Custom Capital Factor. The calculation of the Custom Capital Factor for each of 2020 through 2022 is the same, as set out in Table 1 above.

1.4 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the Custom Revenue Cap Index by Component that Hydro One is proposing to use in this Application to determine Total Revenue Requirement for rate-making purposes for 2019 through 2022.

Table 2: Custom Cap Index (RCI) by Component (%)

Custom Revenue Cap Index by Component	2019	2020	2021	2022
Inflation Factor (I)	1.90	1.90	1.90	1.90
Productivity Factor (X)	-0.45	-0.45	-0.45	-0.45
Capital Factor (C)	1.96	1.83	2.78	1.39
Custom Revenue Cap Index Total	3.41	3.28	4.23	2.84

Table 3 below summarizes the Total Revenue Requirement that would result from the Board's approval of Hydro One's Custom IR, were the Application to be approved as filed.

Witness: Oded Hubert

Table 3: Revenue Requirement by Year

Year	Formula	Revenue Requirement
2018	Cost of Service	$1,499.9 million
2019	2018 Revenue Requirement x 1.0336	$1,551.0 million
2020	2019 Revenue Requirement x 1.0328	$1,601.9 million
2021*	2020 Revenue Requirement x 1.0423 + 10.7M	$1,680.4 million
2022	2021 Revenue Requirement x 1.0284	$1,728.2 million

*Hydro One is proposing to update the 2021 Total Revenue Requirement with updated cost of capital parameters.

1.5 INTEGRATION OF ACQUIRED UTILITIES

Since its last rebasing application, Hydro One has acquired Norfolk, Haldimand and Woodstock. Consistent with the Board's Mergers, Acquisitions, Amalgamations, and Divestitures ("MAADs") Decisions and ratemaking policies, the Acquired Utilities are currently separate from Hydro One for rate-making purposes. 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.

Consistent with the Board's MAADs policies, the financial information and the associated revenue requirement relating to the Acquired Utilities have been excluded from Hydro One's financial information for the test years prior to 2021. For the 2021 and 2022 test years, all financial information presented in this Application includes costs relating to both Hydro One and the Acquired Utilities.

This means that the gross fixed assets and accumulated depreciation of the rate base of the Acquired Utilities has been added to the opening balance of Hydro One's gross fixed assets and accumulated depreciation, respectively, effective January 1, 2021. The resulting increase in rate base of $168.4 million (Exhibit D1, Tab 1, Schedule 1) and capital expenditures is reflected in lines 1 through 6 of Table 1 above and captured as part

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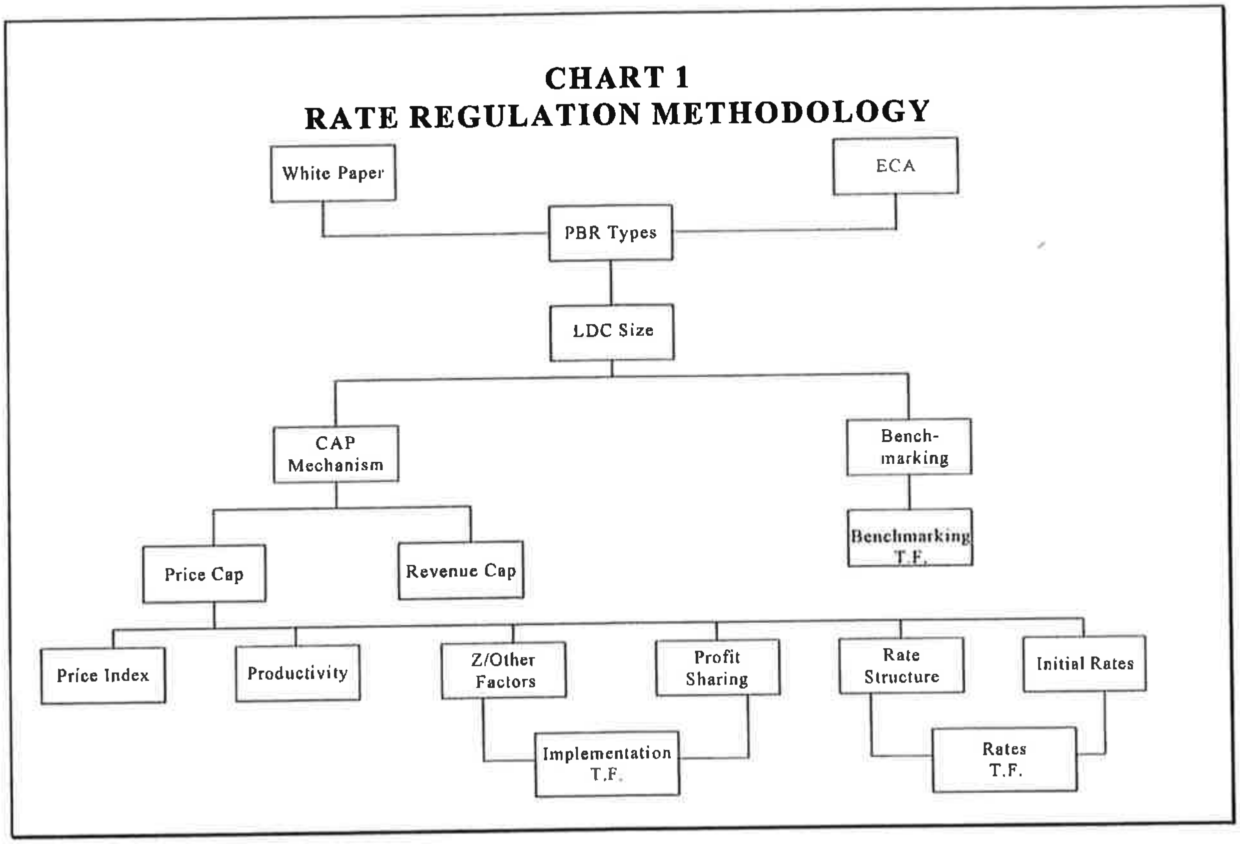
Ontario

REPORT OF THE
ONTARIO ENERGY BOARD
PERFORMANCE BASED REGULATION
CAP MECHANISM TASK FORCE

MAY 18, 1999



regulatory burden, customer impact or return to capital among the LDCs covered by the mechanism. Although initially it was generally judged that a cap mechanism would likely apply to no more than perhaps ten LDCs, the specification of a particular criterion and a target number of LDCs was left to be decided later after preliminary quantitative assessment was completed. Appendix A presents the cap mechanism survey instrument.

In fact, the proposal of the Yardstick Task Force (see Report of the Yardstick Task Force) is that a cap mechanism should apply to all the utilities in the first generation PBR plan. This will allow time for the collection of data to establish a yardstick approach for the subsequent PBR plan (second generation PBR plan).

as an adjunct to price or revenue cap schemes, used to mitigate extreme revenue distribution results.

After considering the pros and cons of the PBR optional mechanisms, the CMTF concluded that the price cap mechanism satisfies the greatest number of principles established by the OEB and, in particular, comes closest to meeting the objective emphasized in the White Paper of providing strong market-based incentives toward improved efficiency.

A position paper submitted by John Todd, Econalysis Consulting Services, on Cap Mechanism alternatives is presented in Appendix B.

2.4 The Price Cap Mechanism

The price cap mechanism provides an upper limit or cap to the price, or basket of prices, charged by an LDC and allows flexibility below the cap. It is designed to allow for the pass through of increases in the prices of inputs to the operations of the LDC and also for normal improvements in productivity in the industry. It may also be structured to allow for corrections of various sorts such as extraordinary events, the sharing of profits outside a pre-defined range, infrastructure investments and service quality adjustments.

The generic formula for the price mechanism is:

$$P_t = P_{t-1} \times (1 + I_t - X_t) + Z_t + Q_t + M_t$$

P_t = Price cap index
I_t = inflation index
X_t = productivity index
Z_t = extraordinary event adjustment factor
Q_t = service quality adjustment factor
M_t = profit-sharing adjustment factor

2.3 Selection of a Cap Mechanism

Each of the remaining three principal types of cap mechanisms was examined against the background of the set of principles established by the OEB for the implementation of PBR and described in the Staff Report referred to above. Each of the options has advantages and disadvantages. The price cap approach has the distinct advantage that it comes the closest of the three to replicating the process of competitive markets. The price of the final product in the market place incorporates the influence of changes in the price of factors of production and in productivity gains. The individual firm takes the price as given and attempts to maximize profits by controlling costs and/or achieving productivity gains beyond those that have been projected. This has the effect of reducing the volatility of prices compared to the revenue cap mechanism. The main drawback of a price cap PBR is that it leaves the LDC exposed to changes in energy throughput. Some have argued that the incentive for the utility to maximize throughput under the price cap mechanism is a drawback. On the other hand this may be seen as an effective use of available capacity. In any case, the impact of throughput variations can be mitigated through rate design and the use of profit-sharing mechanisms.

The revenue cap mechanism attempts to resolve the throughput problem associated with a price cap PBR. Instead of setting a price cap it sets a revenue cap. However, in resolving this problem it creates others. Specifically, once the revenue cap has been set the LDC has an incentive to set prices at levels that would under utilize the capacity of its system. This discretionary control over prices could also lead to greater price volatility. Moreover, the revenue cap mechanism requires throughput growth projections and the use of true-ups in the event of errors in any of the projections that make up the revenue cap. Perhaps, most importantly, it does not focus on the setting of relative prices and providing a set of incentives within this framework that encourages optimal efficiency.

Earnings-sharing or "sliding scale mechanisms" are closest to traditional cost of service/ rate of return (COS/ROR) regulation in that LDC performance is monitored in relation to return on equity (ROE) targets and sharing mechanisms are triggered when actual ROE falls outside a predetermined range. These plans involve a greater degree of regulatory oversight and incorporate fewer of the efficiency incentives than the other mechanisms. They are best seen

RP-1999-0034

IN THE MATTER OF a proceeding under sections 19(4), 57, 70, and 78 of the *Ontario Energy Board Act, 1998* S.O. 1998, c. 15, Sched. B to determine certain matters relating to the Proposed Electric Distribution Rate Handbook for licensed electricity distributors.

BEFORE: George Dominy
Vice Chair and Presiding Member

Paul Vlahos
Member

Sally Zerker
Member

DECISION WITH REASONS

January 18, 2000

2.1.8 The Board has broad discretion under the Act to employ any method or technique in discharging its responsibilities to set just and reasonable rates.

2.1.9 The Board confirms its position that PBR is the appropriate mechanism to be used in bringing the electricity distribution utilities under the authority of the Ontario Energy Board.

2.1.10 With respect to the arguments regarding the use of price cap for all the distribution utilities, while there may be alternative PBR mechanisms that may hold promise, the Board notes that the task forces indicated that, at this time because of lack of consistent data, insufficient time, and insufficient resources, it was not possible to pursue other mechanisms, such as the yardstick mechanism that was the preference of many parties. Further, the Board is of the opinion that price cap regulation for all the electricity distribution utilities represents a simple approach that will provide incentives for efficiency improvements and will at the same time provide the ability to maintain service quality over the course of the first generation PBR plan. The Board therefore adopts the price cap mechanism for first generation PBR.

2.1.11 With respect to the suggestion by some parties that the initial term ought to be longer than three years, the Board finds that the three-year term provides a fair balance of the risks of potential "bad outcomes" and sufficient time for the distribution utilities to gain experience with PBR. In addition, the three-year term would allow the collection of sufficient data for the Board and the industry to assess the various mechanisms and will establish a baseline for second generation PBR. The Board therefore concludes that a three-year first generation transition PBR term for years 2000-2002 is appropriate. Given the relatively short period of first generation PBR, the Board does not envisage the need to include any provision to allow utilities to exit the plan, commonly known as "off-ramp".

2.1.12 On the issue of whether a growth factor should also be included in the price cap mechanism, the Board accepts Dr. Bauer's testimony that a growth allowance is implicit in a price cap PBR regime and therefore explicit inclusion of a growth factor in the price cap formula is unnecessary.

PBR OPTIONS FOR

ELECTRICITY DISTRIBUTION

IN ONTARIO

ONTARIO ENERGY BOARD STAFF REPORT

October 15, 1998

importance in implementing yardstick regulation is the requirement that each firm be benchmarked against a peer group of similarly situated and structured firms. Otherwise, inappropriate comparisons due to intrinsic cost differences could create inter-firm inequities in establishing benchmark prices.

The sliding scale approach to PBR simply sets a cap on earnings beyond which excess earnings are shared between ratepayers and shareholders according to a pre-set formula. This approach is probably the least difficult of the three described here to administer, but requires careful consideration of the appropriate threshold earnings level and split of excess earnings. The level of earnings at which sharing begins and the level of sharing can impact firm behavior and investment decisions. Furthermore, the existence of earnings sharing in PBR plans in general can act as a backstop in the event the PBR plan results in "unanticipated earnings."

Many regulators are uncomfortable with PBR plans to the extent that they might encourage "excessive or inappropriate" cost cutting unless firms are constrained to consider appropriate service standards. PBR regulation should provide more explicit accounting for non-price or productivity incentives by linking allowed returns to standards in any of several areas deemed important to service quality and reliability. While this approach can be data intensive, in that it usually requires developing and tracking industry and individual firm performance in the targeted areas, it can help ensure that PBR induced gains in cost and efficiency do not come with associated degradation in service quality, reliability, or safety. It also requires careful consideration of the allowable increases/decreases in returns resulting from performance against these benchmarks.

Some PBR plans combine aspects of these approaches, in effect, creating a custom-tailored mechanism to better handle regulatory objectives and concerns. For example, price cap plans can be constructed to include earnings sharing and performance standards. Certainly, experience with PBR implementation has indicated the growing concerns of regulators to require management to appropriately factor performance, quality, or service standards into its operations.

4.2 PRICE CAP REGULATION

In price cap regulation prices are capped independent of costs. The test year's price caps are set to the price of the previous year indexed by an inflation factor offset by a productivity factor. Extraordinary events (Z factors) are taken into account in setting the price cap.

Price caps are a form of utility regulation that focuses initially on controlling prices directly, rather than indirectly as under COS/ROR regulation. Under COS/ROR regulation a utility's prices for services are the result of controls on cost-based revenues – i.e., prices are set to recover expenses and returns to capital. The allowed rate of return fixes the ex-ante profits of the firm and, together with expenses, establishes the firm's revenue requirement. Prices are "simply"

Similarly, actual price cap plans have utilized a number of approaches to determine the change in productivity among the regulated firms. In some cases, a negotiated process was employed. In other cases, government statistical measures provided the required information. Finally, in some cases data from the companies was employed to gauge the recent or expected improvement in productivity. In fact, most plans combine several approaches in determining the size of the productivity "offset." As with the price index, tradeoffs exist among these approaches: accuracy, timeliness and cost effectiveness must be carefully balanced.

It is noted that the actual productivity offset selected should be based on peer group, not individual firm performance. A firm which improves its productivity more than the peer group standard imposed in the plan can retain the increased earnings associated with its superior performance (within the provisions of the plan). Since each firm is similarly incented to improve relative to the peer group average, the rate of productivity change should increase over the term of the plan, assuming sufficient time for the firm's investment to payoff.

However, application of a price cap approach to network-based energy utilities may entail two potential disadvantages, which must be considered. Both of these disadvantages tend to be mitigated in revenue cap plans discussed below. First, price cap regulation tends to encourage increased sales by the utility since prices, but not quantities, are constrained under the plan. This incentive, in some circumstances, may be inconsistent with energy efficiency objectives. Such incentives to increase sales can be tempered through a variety of plan design features. For example, an earnings sharing mechanism reduces the firm's incentive to increase profits in general. Thus, although not specifically designed for this purpose, earnings sharing could be used in combination with price caps. As a second option, regulators could include energy efficiency objectives, which reduce sales quantities and their associated rewards/penalties among the performance standards included in the plan. Finally, regulators could include expenditures for energy efficiency programs among the Z factors in the plan (i.e., cost pass throughs).

Second, price cap approaches may potentially be less suitable in cases where the regulated firm has high fixed costs and faces volatility in revenues beyond its control. For the network industries under price cap regulation, significant declines in energy throughput can result in revenue shortfalls without corresponding decreases in network costs.

4.3 REVENUE CAP REGULATION

With a revenue cap the test year's revenue is capped independent of the utility's costs and is set according to the previous year's revenue indexed by an inflation factor adjusted by a productivity factor. Extraordinary events and growth are factored into the revenue cap.

Of course, such applications assume that differences in prices between the aggregate and industry specific measures remain fixed over the term of the plan.

Revenue caps are similar to price caps except that revenue is adjusted by changes in input prices net of changes in productivity. In some plans, allowed revenue is also adjusted to reflect changes in the number of customers. The incentive provided a regulated firm to reduce costs under a revenue cap is similar to that provided by a price cap. Furthermore, all of the issues raised in the discussion of price caps with respect to price indices, productivity offsets, standards, sharing and term hold for revenue caps. However, revenue caps differ from price caps in reducing both the incentive and risk associated with sales.

Since under revenue caps a firm's allowed revenue is constrained, the firm's incentive is to reduce not only unit costs (say average cost per unit output), but also the number of units sold such that total profits are maximized. Thus, revenue caps may be intrinsically more compatible with energy efficiency programs which reduce demand, than are price caps. Similarly, variations in sales due to factors beyond management's control, e.g., customer migration may not cause the utility to suffer severe financial distress.

This pricing feature of revenue caps has been criticized since it may also encourage the utility to raise its prices, thus reducing sales to stay within the revenue cap, and maximizing profits. Other theoretical criticisms maintain that price caps are more efficient in setting relative prices and that pricing in general under revenue caps is more variable. Therefore, some analysts have suggested combining features of both price and revenue cap plans to offset the relative disadvantages of each approach separately. Thus, one could specify a revenue adjustment within a price cap plan or a price adjustment within a revenue cap plan.

4.4 INDUSTRY AVERAGE COST OR "YARDSTICK COMPETITION" APPROACH

In situations where the regulator is confronted with the task of regulating a large number of companies, each employing generally similar technology to produce a product or service, and servicing potentially dissimilar markets (e.g., urban vs. rural, residential vs. industrial/commercial) the Yardstick Competition ("YC") approach can be effective. The key element of this approach is the use of industry or appropriately partitioned subgroup cost/performance measures to create external peer group benchmarks.

For example, firms could be partitioned into peer groups (e.g., small, rural operators). If the external benchmark were the average cost of the peer group, then each firm could charge an average price equal to the peer group's average cost.

Each firm would have an incentive to lower its own costs, since to do so would increase its profits relative to the price ceiling established on the peer group's average cost. Over time, efforts by each firm to become more efficient would result in decreases in costs and consequent reductions in the price ceiling. Each firm would have an incentive to service new customers or offer innovative services if the associated additional activities increase earnings.

Ontario Energy Board

Ontario

Report of the Board

Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach

October 18, 2012

Table 1: Rate-Setting Overview - Elements of Three Methods

		4th Generation IR	Custom IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) Industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Stretch factor	Productivity factor Case-by-case	Highest 4th Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels.		

The Board is establishing three rate-setting methods. Each distributor will select the method that best meets its needs and circumstances, and apply to the Board to have its rates set on that basis. 4th Generation Incentive Rate-setting ("4th Generation IR"), which builds on 3rd Generation IR, is most appropriate for distributors that anticipate some incremental investment needs will arise during the plan term. The Board expects that this method will be appropriate for most distributors.

Distributors with relatively steady state investment needs (i.e., primarily sustainment), may prefer the Annual Incentive Rate-setting Index ("Annual IR Index").

The Custom Incentive Rate-setting ("Custom IR") method may be appropriate for distributors with significantly large multi-year or highly variable investment commitments with relatively certain timing and level of associated expenditures.

2.2.1 Description of the Three Rate-setting Methods

4th Generation IR

Building on the current 3rd Generation IR, the 4th Generation IR method includes certain enhancements to better align indexing of rates with the inflation faced by distributors in Ontario and to strengthen the efficiency incentives inherent in the rate-adjustment mechanism. The 4th Generation IR method will be appropriate for distributors that anticipate that some incremental investment needs may arise during the term of the rate method.

Under this method, rates are set on a single forward test-year cost of service basis and subsequently indexed by the 4th generation price cap index formula. The Board will retain a comprehensive price cap form of adjustment mechanism. The Board believes that the price cap approach, like that used in the Board's earlier IR plans, continues to be appropriate for most distributors.

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Ontario Energy Board

Filing Requirements For
Electricity Distribution Rate Applications
- 2017 Edition for 2018 Rate Applications -

Chapter 3

Incentive Rate-Setting Applications

July 20, 2017

Table 1: Rate-Setting Overview – Elements of the Three Methods

		Price Cap IR	Custom IR	Annual IR Index
Setting of Rates				
"Going in" Rates		Determined in single forward test-year cost of service review	Determined in multi-year application review	No cost of service review, existing rates adjusted by the Annual Adjustment Mechanism
Form		Price Cap Index	Custom Index	Price Cap Index
Coverage		Comprehensive (i.e., Capital and OM&A)		
Annual Adjustment Mechanism	**Inflation**	Composite Index	Distributor-specific rate trend for the plan term to be determined by the Board, informed by: (1) the distributor's forecasts (revenue and costs, inflation, productivity); (2) the Board's inflation and productivity analyses; and (3) benchmarking to assess the reasonableness of the distributor's forecasts	Composite Index
	Productivity	Peer Group X-factors comprised of: (1) industry TFP growth potential; and (2) a stretch factor		Based on 4th Generation IR X-factors
Role of Benchmarking		To assess reasonableness of distributor cost forecasts and to assign stretch factor		n/a
Sharing of Benefits		Stretch factor	Productivity factor Case-by-case	Highest 4th Generation IR stretch factor
Term		5 years (rebasing plus 4 years).	Minimum term of 5 years.	No fixed term.
Incremental Capital Module		On application	N/A	N/A
Treatment of Unforeseen Events		The Board's policies in relation to the treatment of unforeseen events, as set out in its July 14, 2008 EB-2007-0673 Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, will continue under all three menu options.		
Deferral and Variance		Status quo	Status quo, plus as needed to track capital spending against plan	Disposition limited to Group 1 Separate application for Group 2
Performance Reporting and Monitoring		A regulatory review may be initiated if a distributor's annual reports show performance outside of the ±300 basis points earnings dead band or if performance erodes to unacceptable levels		

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Ontario Energy Board

Commission de l'énergie de l'Ontario

Handbook for Utility Rate Applications

October 13, 2016

Natural Gas Utilities

Natural gas utilities may choose either Custom IR or Price Cap IR. Under either approach, the term must be a minimum of 5 years. For Price Cap IR it would include a cost of service year and at least four years using an incentive adjustment mechanism.

Ontario Power Generation

The OEB established expectations that payments for OPG will be based on Price Cap IR for the hydroelectric business and Custom IR, based on the RRFE principles, for the nuclear business. The OEB may set out its expectations for future applications in its next decision and order for OPG.

Specific Considerations for Custom Incentive Rate setting

The OEB has now received and decided a number of Custom IR applications and is in a position to provide further guidance on the minimum standards for Custom IR applications to ensure that the performance-focused and outcomes-based approach is achieved as intended. A Custom IR application is by its very nature custom, and therefore no specific filing requirements have been established. However, any utility filing a Custom IR application should be informed by the cost of service filing requirements and this Handbook. The sections that follow set out the OEB's minimum standards for certain key elements of Custom IR applications.

There is no threshold test or eligibility requirement for a Custom IR application. The test for the adequacy of the application is the extent to which its features contribute to the achievement of the OEB's RRF goals and whether it meets the following standards:

- Term: A Custom IR must have a minimum term of five years. The OEB has determined that this term supports a longer term approach to planning to smooth expenditures and pace rate increases, strengthens efficiency incentives and supports innovation. Longer terms can be proposed with appropriate mechanisms for consumer protection as discussed below.

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast).

The index must be informed by an analysis of the trade-offs between capital and operating costs, which may be presented through a five-year forecast of operating and capital costs and volumes. If a five-year forecast is provided, it is to be used to inform the derivation of the custom index, not solely to set rates on the basis of multi-year cost of service. An application containing a proposed custom index which lacks the required supporting empirical information may be considered to be incomplete and not processed until that information is provided.

It is insufficient to simply adopt the stretch factor that the OEB has established for electricity distribution IRM applications. Given a utility's ability to customize the approach to rate-setting to meet its specific circumstances, the OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors.

- Benchmarking: Benchmarking is a fundamental requirement of a Custom IR application, both internal benchmarking to demonstrate continuous improvement and external benchmarking as identified in Section 5. A Custom IR application without benchmarking will be considered incomplete.

- Performance Metrics: The OEB has established a scorecard for electricity distributors, however, additional performance metrics should also be proposed so that expected outcomes can be monitored. All other utilities must propose a comprehensive scorecard that is informed by the scorecard for electricity distributors, but specifically includes other performance metrics aligned to the outcomes identified in the application. This is required for both Custom IR and cost of service rate applications.

- Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five-year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application.

The adjudication of an application under the Custom IR method requires the expenditure of significant resources by both the OEB and the utility. The OEB therefore expects that a utility that applies under Custom IR will be committed to that method for the duration of the approved term and will not seek early termination or in-term updates except under exceptional circumstances and with compelling rationale.

A Custom IR application can include a five year forecast of all costs with proposed rates for each year that consider both these costs and the proposed productivity improvements reflected in the custom index. A utility that cannot forecast its needs within the five year term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances.

The ICM and ACM mechanisms for funding capital for electricity distributors, or any similar mechanism approved for transmitters, natural gas distributors or OPG, are not available for utilities setting rates under Custom IR.

An acceptable adjustment during a Custom IR term is a Z factor mechanism for cost recovery of unforeseen events. The OEB has a policy for Z factors for electricity distributors and transmitters that applies for any rate-setting option chosen by a utility. The OEB has established a materiality threshold for electricity distributors for eligibility to claim for a Z factor event. Electricity transmitters are expected to propose a materiality threshold in their applications. The OEB has approved Z factor mechanisms for natural gas distributors in previous proceedings, and they may propose mechanisms in their future rate applications.

Given the custom nature of a Custom IR application, utilities may propose alternative mechanisms for unforeseen events to coordinate better with other aspects of their custom proposals. In doing so they should consider the OEB's expectations for protecting customers from excess earnings, as discussed in the next section.

- Protecting Customers: A key objective of incentive regulation is to drive productivity improvements within the utilities. The OEB has determined that with the Custom IR rate setting option, customers will benefit from the expected productivity improvements during the term through the custom index.

  Utilities that achieve productivity improvements above what is expected are allowed to keep certain earnings above the approved ROE. However, the OEB expects utilities filing a Custom IR application to propose one or more mechanisms to protect customers from utility earnings that become excessive. Proposals would typically include mechanisms such as off ramps (discussed below) and earnings sharing but could include other approaches specific to a utility's circumstances.

For electricity distributors, the OEB has established an off-ramp that involves a threshold above the distributor's approved return on equity at which a regulatory review may be triggered.[17] An electricity distributor can propose an alternative threshold that provides greater protection for customers. Other utilities may propose an off-ramp that takes into consideration the OEB's objective of protecting customers from excess earnings.

The OEB does not require a Custom IR to include an earnings sharing mechanism, except in the context of deferred rebasing periods as part of electricity distributor consolidation[18]. While an earnings sharing mechanism protects customers from excess earnings, it can diminish the incentives for a utility to improve their productivity, and any benefits to customers are deferred. The requirement for a custom index ensures that benefits are shared immediately with customers through productivity commitments.

If a utility proposes an earnings sharing mechanism as its mechanism to protect customers against excess earnings, it should be based on overall earnings at the end of the term, not an assessment of earnings in each year of the term, consistent with the approach to limiting mid-term updates.

If a Custom IR application does not meet all of these requirements, the OEB may impose a reduced term, reject the application or determine that an application is incomplete and will not be processed until the requirements are met.

[17] This policy was reaffirmed in the RRFE Report.
[18] *Report of the Board: Rate-Making Associated with Distributor Consolidation*, March 26, 2015

Building Owners and Managers Association Toronto Interrogatory # 144

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-02 Page: 6

Interrogatory:
The rates referred to in the third bullet on p2 are the rates that are derived from the application of the revenue cap I-X formula to the test year (2018) and each subsequent year. Please explain line 7 of Table 1, the productivity factor is not the 0.45% stretch factor meant to be applied to the revenue.

Response:
The 3rd bullet point on page two of the referenced Exhibit discusses the elimination of the Seasonal customer class. Hydro One is unclear how this reference ties with Table 1.

As noted on page 4 of Exhibit A, Tab 3, Schedule 2, the productivity factor "X" in Hydro One's proposed Revenue Cap Index is equal to the sum of an industry total factor productivity measure (0%) and a stretch factor (0.45%). It is applied to the capital related revenue requirement shown on line 6 of Table 1 consistent with the OEB's findings in its decision on the Custom IR proceeding for Toronto Hydro- Electric System Ltd. (EB-2014-0016). In that decision, the OEB stated that the stretch factor should apply to total costs (i.e. both capital and OM&A).

Witness: D'ANDREA Frank

Consumers Council of Canada Interrogatory # 10

Issue:

Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:

A-03-02 Page 1

Interrogatory:

HON is applying for a Revenue Cap Index with a Custom Capital Factor. What other approaches were considered by HON? Why were they rejected? Did HON use external consultants in developing the Rate Plan? If so, please provide any studies produced by those consultants

Response:

Hydro One reviewed the rate-setting options available to distributors under the RRF in conjunction with other regulatory mechanisms such as the ACM/ICM and determined that the Custom IR method was required to meet Hydro One's operational requirements. As noted on page 2 of Exhibit A, Tab 3, Schedule 2, Hydro One based its RCI on the methodology approved by the OEB for Toronto Hydro-Electric System Limited in EB-2014-0016. Hydro One reviewed the Custom IR mechanisms that were approved by the OEB for other Ontario utilities and determined that the OEB-approved methodology for Toronto Hydro was most consistent with the guidance provided by the OEB in its Handbook for Utility Rate Applications. Hydro One did not use external consultants in developing its Revenue Cap Index.

Witness: D'ANDREA Frank

EB-2014-0016

NOTICE OF APPLICATION AND WRITTEN HEARING
Direct Energy Marketing Limited
Application for Gas Marketer Licence

Direct Energy Marketing Limited has applied to the Ontario Energy Board under section 50 of the of the *Ontario Energy Board Act, 1998,* (the "Act") for a gas marketer licence. The granting of this licence would enable the applicant to market natural gas in Ontario. The Board has assigned the application file number EB-2014-0016.

The application will be decided by an employee of the Board who has been delegated this authority pursuant to section 6 of the Act. The employee does not intend to provide for an award of costs when deciding this application.

How to see Direct Energy Marketing Limited's Application

A copy of the non-confidential portion of the application and related documents are available for inspection at the Board's office in Toronto. A copy can also be viewed at the applicant's office at the address indicated below.

How to Participate in the Hearing

The Board intends to proceed with this application by way of written hearing unless a party satisfies the Board that there is a good reason for not holding a written hearing. If you object to the Board holding a written hearing for this application, you must provide written reasons why an oral hearing is necessary. Any submissions objecting to a written hearing must be received by the Board and copied to the applicant by **March 10, 2014.**

Any parties, who wish information and material from the applicant that is in addition to the applicant's pre-filed evidence with the Board and that is relevant to the hearing, shall

Ontario

Ontario Energy Board
Commission de l'énergie de l'Ontario

DECISION AND ORDER

EB-2014-0116

TORONTO HYDRO-ELECTRIC SYSTEM LIMITED

Application for electricity distribution rates effective from May 1, 2015 and for each following year effective January 1 through to December 31, 2019

BEFORE: Christine Long
Presiding Member

Ken Quesnelle
Vice Chair and Member

Cathy Spoel
Member

December 29, 2015

3.4 The Custom Framework Proposed by Toronto Hydro (Issue 2.2)

Background

The OEB must decide whether the proposed Custom formula proposed by Toronto Hydro is appropriate. Toronto Hydro has proposed that distribution rates in Years 2 through 5 be adjusted annually by using a custom Price Cap Index (PCI):

PCI = I – X + C

Where,

- **"I"** is the OEB's inflation factor, determined annually
- **"X"** is the sum of:
  - The OEB's productivity factor
  - Toronto Hydro's custom stretch factor
- **"C"** provides incremental funds that are necessary to fund capital needs

Toronto Hydro has proposed two changes to the price cap mechanism that the OEB normally uses.

First, based on the benchmarking it has filed to support this Application, Toronto Hydro is proposing a stretch factor of 0.3%, rather than the 0.6% that would otherwise be applied by the OEB to Toronto Hydro. Second, Toronto Hydro has proposed the use of a custom capital "C" factor

3.4.1 The Custom Stretch Factor

a) The Appropriate Stretch Factor

The OEB undertakes annual benchmarking for all Ontario distributors and based on those benchmarking results assigns each distributor a stretch factor. One of five possible stretch factors is assigned based on whether the distributor's costs are above or below the benchmark. The "middle" stretch factor is 0.3% which represents an "average" performer. The stretch factor is part of the formula that is used to adjust a distributor's rates. Based on the OEB's current methodology, Toronto Hydro's stretch factor is 0.6%. Toronto Hydro submitted benchmarking evidence in the form of Power System Engineering's Econometric Benchmarking Report (the PSE Report). On the basis of this report, Toronto Hydro argues that it should be assigned a "better" stretch factor in the proposed Custom PCI framework of 0.3%. Toronto Hydro argued that

PSE's total cost benchmarking evidence demonstrates the reasonableness of its past and projected cost levels by demonstrating that Toronto Hydro is within +/- 10% of the benchmark which supports the assignment of the middle (0.3%) stretch factor.

OEB staff engaged Dr. Lawrence Kaufmann of the Pacific Economic Group (PEG) to analyze Toronto Hydro's proposed stretch factor and custom capital factor, to advise on Toronto Hydro's Application generally, and to assess the design of the Custom IR plan. PEG was also asked to evaluate the technical work of PSE and, where relevant, to provide alternate cost and reliability benchmarking evidence.

As a result of the annual benchmarking the OEB undertakes for all Ontario distributors, the OEB has detailed benchmarking evidence involving both costs and reliability for Toronto Hydro. Based on this benchmarking data, Toronto Hydro is classified as a high cost performer with a stretch factor of 0.6%. Parties argued that it would not be unreasonable for the OEB to continue to apply a stretch factor of 0.6%, and argued that Toronto Hydro has not justified why its current stretch factor of 0.6% is inappropriate.

Some parties argued for an even higher stretch factor. They proposed a stretch factor of 1.0%. OEB staff, based on Dr. Kaufman's evidence, took the position that the OEB should consider a higher stretch factor to, in effect adjust for the fact that Toronto Hydro was a relatively poor performer in prior years. OEB staff argued that one way to implement this would be to set a stretch factor for the term of this Custom IR plan that is higher than 0.6%. Most parties argued that a stretch factor between 0.6% and 1% would be appropriate. They also submitted that the benchmarking analysis demonstrates that Toronto Hydro's costs are significantly higher than other Ontario utilities and its US peers. They also argued that the 0.3% stretch factor proposed by Toronto Hydro does not incent productivity.

Toronto Hydro argued that adopting any stretch factor greater than 0.6% would be contrary to OEB policy and arbitrary.

Findings

The appropriate stretch factor for Toronto Hydro is 0.6%. The OEB finds that the evidence as a whole is not sufficiently persuasive to support the change sought by Toronto Hydro.

The experts' evidence on benchmarking differs in three key areas;

1. The Urban core variable
2. Approach to CDM costs
3. Asset price inflation costs (capital cost escalation rate)

- 2016 – 4.47%
- 2017 – 8.25%
- 2018 – 6.69%
- 2019 – 5.01 %

Toronto Hydro stated that the premise of the inclusion of a C-factor is to allow it to address the RRFE's statement that the Custom IR framework is suitable for utilities with significant multi-year capital investment requirements, as it is clear that the standard 4th Generation IR framework is not. Toronto Hydro further stated the proposed C-factor is designed as a rate adjustment mechanism that is directly proportional to the degree of capital investment required by Toronto Hydro. It is comprised of two sub-components which are designed to: (i) reconcile Toronto Hydro's capital investment needs in a price cap framework, and (ii) return to ratepayers the funding already provided for capital through the standard "I-X" increase.

PEG reviewed the C-factor and stated that it should include an adjustment for the growth in Toronto Hydro billing determinants to prevent the C-factor from over-recovering capital cost. PEG concluded that its recommended C-factor adjustment would eliminate over-recovery of capital costs and reduce Toronto Hydro's price growth by an estimated 1.5% per annum in 2016 through 2019.

Most parties supported the use of the C-factor, though some issues were raised and modifications proposed. Most parties also supported the PEG proposal for some form of billing determinant adjustment. OEB staff submitted that Toronto Hydro's failure to provide five full years of cost forecasts in support of the C-factor calculations resulted in approximations and that more thorough calculations should be provided.

Findings

The OEB is not opposed to the C-factor mechanism as proposed, but the quantum will change as it relates to revenue requirement to reflect the reduction in capital spending approved by the OEB. Under the Application proposed by Toronto Hydro, the C-factor is the mechanism by which increases in capital spending are funded.

C-factor growth determinant

Background

PEG's evidence suggested that the C-factor should include an adjustment for the growth in Toronto Hydro's billing determinants in order to prevent the C factor from over-recovering capital costs. PEG stated that to ensure the C factor recovers only the change in incremental capital spending, it should be modified to reduce the change in prices by the annual change in a revenue share weighted average of Toronto Hydro's billing determinants. PEG recommended an adjustment estimated at 1.5% per annum in 2016 through 2019. Toronto Hydro did not object to including such a growth factor, but disagreed with the magnitude of the adjustment proposed by PEG and the other parties. Toronto Hydro argued that a more appropriate growth factor adjustment would be closer to 0.3% rather than PEG's proposed 1.5%.

Findings

The OEB is of the view that a growth factor is reasonable in order to prevent an over-recovery of costs. Toronto Hydro is in the best position to anticipate what its growth factor will be over the term of the rate plan. The 0.3% suggested by Toronto Hydro appears to be reasonable as it is based on Toronto Hydro's detailed forecast of its load and customers by class for the 2015 to 2019 period[19] which has been accepted later in the Decision.

The ICM Application

The 2012-2014 Incremental Capital Module (ICM[20]) was the source of some discussion in the Application. Parties argued that approximately 86% of proposed capital spending in the five year DSP is similar in nature to the ICM work. Therefore the results of the ICM true up were of interest to many of the parties. Toronto Hydro advised that the ICM true-up was to be completed in 2015 Q2 after 2014 financial close and the full reconciliation by segment of work completed during the ICM period. Toronto Hydro did advise that expenditures for the 2012-2014 ICM program are forecasted to be within 5% of overall OEB-accepted forecast amounts on a three year basis. The OEB observes that projects under the previous ICM application appear to be advancing as scheduled and reasonably within the forecast costs. However, given the limited information that the panel had before it in this proceeding, it did not form the basis of any findings.

Revenue Requirement

3.6 Rate Base (Issue 5.1)

Background

The OEB must determine whether the rate base component of the revenue requirement for 2015 is appropriate.

[19] Reply Argument, p. 193
[20] Ref IR 2B-SIA-15; Ex 1B-T2-S4

Vulnerable Energy Consumers Coalition Interrogatory # 3

Issue:
Issue 7: Is Hydro One's proposed Custom Incentive Rate Methodology, using a Revenue Cap Index, consistent with the OEB's Rate Handbook?

Reference:
A-03-02 Page: 2

Interrogatory:
a) Starting at page 2 of the reference are five factors Hydro One claims make a Revenue Cap approach superior to Price Cap rate setting. For each of these factors please explain why Hydro One's proposal is a superior approach. For example, Hydro One claims Revenue Cap provides greater flexibility under which to eliminate rate classes (Seasonal). However, it is not clear why this should be the case. Please explain.

Response:
a) The proposed Revenue Cap Index is superior to Price Cap rate setting for Hydro One's overall circumstances because it allows for better flexibility and provides greater transparency when integrating the Acquired Utilities in to Hydro One's rate structure.

In keeping the rate setting mechanism at the revenue level, rather than the price level, Hydro One can more easily, and more transparently:

- add the incremental rate base and OM&A associated with the Acquired Utilities to Hydro One's revenue requirement;
- update its billing determinants and load forecast to integrate customers of the Acquired Utilities in to the proposed and existing rate classes, as applicable; and
- complete an updated cost allocation study at the time of integration to ensure fairness in the allocation of costs across all rate classes.

Price Cap IR and Revenue Cap IR are equally capable of continuing the transition to fully-fixed residential rates, eliminating the seasonal class and accommodating changes to the rate design of commercial and industrial electricity customers over the Custom IR term. Hydro One listed these additional items to provide comfort to the OEB and intervenors that the proposed Revenue Cap IR approach would not negatively impact the implementation of these key policy initiatives.

Witness: D'ANDREA Frank

OEB Staff Interrogatory # 21

Issue:
Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:
A-03-02 Page: 1-2 – Revenue Cap Proposal
Hydro One describes its Custom IR proposal as:

> *"Hydro One's application is based on a Custom Incentive Rate-Setting approach for a 5- year period. The methodology utilized is a Revenue Cap IR in which revenue for the test year t+1 is equal to the revenue in year t inflated by the Revenue Cap Index ("RCI") set out below."*

On page 2, Hydro one gives the formula as:

The Custom Revenue Cap Index (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.

Typically, a revenue cap formula is of the form:

$$Rev_t = Rev_{t-1} \times (1 + (I - X + g))$$

where the I and X are as described above, and g (growth) is based on growth in demand (customers, consumption, energy demand). Revenues are capped by the formula, with rates set to recover the annual revenue requirement updated by this formula.

In Hydro One's proposal, the updated revenue requirement will be converted into rates each year based on the demand forecasted (where forecasted numbers of customers, kWh and kW, as

Witness: D'ANDREA Frank

applicable) are used as the billing determinants for the revenue requirement as allocated between customer classes and between fixed and variable charges.

Interrogatory:

a) Growth in operating scale is an important driver of cost growth. What is the rationale for a revenue cap index that does not include a scale escalator?

b) Please confirm that, under Hydro One's proposal, it has an opportunity, under certain conditions, of earning more revenues than the revenue requirement adjusted by the annual RCI. For example, if actual demand (as a combination of number of customers, kWh and kW) exceeds Hydro One's forecasted demand, Hydro One would receive more revenues as it would be the lower forecasted demand which would be the billing determinants for establishing rates in the year. In the alternative, please explain.

c) Why does Hydro One characterize its proposal as a revenue cap, even though it is little different than Toronto Hydro-Electric System Limited's Custom IR approved in EB-2014-0016, which was characterized there as a Price Cap?

Response:

a) Under Hydro One's RCI, any additional capital requirements required to serve any load/demand growth would be captured in the formula through the Custom Capital Factor. The expected growth in billing determinants would be captured in rates through the rate design process outlined in Exhibit H1, Tab 1, Schedule 2, wherein billing determinants are updated annually in line with the expectation of the load forecast. As a result of these two factors, Hydro One does not believe that a growth factor is required in the RCI.

b) The potential to over-recover revenue, as described by OEB staff's question, exists in all instances where rates are set based on forecast billing determinants. Likewise there is potential that Hydro One could under earn revenue if the actual number of customers, kWh and kW is lower than forecasted billing determinants. This risk is not driven by Hydro One's proposed RCI but by the fact that actual load will not exactly match the load forecast underpinning rates. A utility that was under a multi-year cost of service rate setting framework would have the same opportunity to over/under earn revenue as a utility subject to an incentive rate-setting structure such as Hydro One's proposed RCI.

c) Hydro One's proposal is appropriately characterized as a Revenue Cap Index (RCI) because the index is used to escalate the prior year's revenue requirement. Toronto Hydro's Custom IR Price Cap Index is used to directly adjust the prior year's base distribution rates.

Witness: D'ANDREA Frank

OEB Staff Interrogatory # 25

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 3 and 8 – Output Quantity Index

PSE states on page 3 of its Productivity Report that:

> *"The outputs used for the industry TFP trends should also be generally based on billing determinants that are related to how the distributor collects revenue. However, in determining performance, other non-revenue producing, valued outcomes should be incorporated into the evaluation. The condition to have outputs and weights that approximate distribution revenue collection would exclude the use of the adjusted TFP index as the basis for the productivity factor in incentive regulation, even if we had an industry-wide measure of it."*

PSE states on page 8 of the same report that:

> *"[t]he objective for the TFP calculated in the 4th Generation IR proceeding (EB-2010-0379) was to calculate the most appropriate productivity factor to be used in the **price** cap escalation formula." [emphasis added]*

Interrogatory:

a) Hydro One's proposed Custom IR plan features a revenue cap index. Trends in billing determinants are widely recognized to be pertinent in the choice of an X factor for a price cap index. Please explain why they are also pertinent in the design of an X factor for a revenue cap index.

b) Ontario utilities are transitioning to rate designs with high fixed charges for Residential and possibly also for other (e.g., commercial and industrial) classes. Does this reduce the weights that are appropriate for volume and peak demand variables in the output index for productivity research intended to establish a price cap index productivity factor?

Witness: PSE

Response:

a) Billing determinant trends are not pertinent to the design of an X Factor in the context of a revenue cap index. Billing determinant trends are pertinent in the context of the design of an X Factor in the context of a price cap index. PSE extended and replicated, as closely as we could, PEG's 4GIR productivity trends in the PSE Productivity Report. It is PSE's understanding the 4GIR productivity trends calculated by PEG and used as the basis for PEG's price cap X Factor recommendation used cost elasticity weights, rather than billing determinant weights. In the context of a revenue cap, cost elasticity weights are appropriate.

PSE would also note that in a revenue cap index context, an output growth term could be considered in the escalation formula from a mathematical perspective. However, the existence of a capital factor within the escalation formula may be an adequate substitute for an output growth term.

The mathematics behind the output growth term is given below:

The allowed revenue escalation within a revenue escalation formula should mimic the expected growth in costs. Production theory postulates that there should be three main components within the escalation formula. These three components are: input price inflation (I), a productivity expectation (X), and output growth (O).

$$Growth\ Revenue = I - X + Growth\ O \qquad \text{[Equation 1]}$$

The mathematical derivation of Equation 1 is provided below. It begins with the assumption that the allowed growth in revenue should be equal to the expected growth in costs.

$$Growth\ Revenue = Growth\ Cost \qquad \text{[Equation 2]}$$

Basic production theory states that costs equal the product of input prices and input quantities (Q). In turn, the growth in costs will equal the growth in input prices (I) plus the growth in input quantities.

$$Growth\ Cost = I + Growth\ \mathrm{Q} \qquad \text{[Equation 3]}$$

If we add and subtract the same term to the right-hand side of the equation, that is the same as adding zero, and the equation remains unchanged. We will both add and subtract output growth (O) to Equation 3 to develop Equation 4 below.

Witness: PSE

$$Growth\ Cost = I + Growth\ Q + Growth\ O\ - Growth\ O \qquad \text{[Equation 4]}$$

The TFP trend is defined as the change in output quantity minus the change in input quantity. In equation form:

$$TFP\ trend = Growth\ O - Growth\ Q \qquad \text{[Equation 5]}$$

We can rearrange the terms in Equation 4 to the following equation.

$$Growth\ Cost = I - (Growth\ O - Growth\ Q) + Growth\ O \qquad \text{[Equation 6]}$$

And then insert Equation 5 into Equation 6.

$$Growth\ Cost = I - TFP\ trend + Growth\ O \qquad \text{[Equation 7]}$$

Therefore, if we want the growth in revenue to match the growth in cost, then Equation 7 would serve as the mathematical derivation of calculating the growth in revenue. However, in the context of a custom IR application, Hydro One is proposing a capital factor. This capital factor is anticipating the capital needs for the CIR period. It likely will then capture the growth-related capital needs for the CIR period and, at least partially, substitutes for an output factor.

b) The appropriate weights for a price cap index X Factor would reflect the billing determinant revenue weights. To the extent the billing determinant weights are changing, it would be appropriate to reflect that change in a price cap index design. It would not be appropriate in the context of a revenue cap index design to reflect a change in the billing determinant weights since the cost elasticity weights would, presumably, not be impacted due to changing billing determinant weights.

Witness: PSE

Consumers Council of Canada Interrogatory # 3

Issue:
Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:
None

Interrogatory:
Please describe, in detail, the overall planning process that HON undertook in developing its rate plan and in putting together its Application. Please include a complete timeline. Please provide all budget directives and guidance provided to employees.

Response:
The business planning process at Hydro One typically starts in the spring each year. Hydro One's planning group prepares the investment plan as described in section 2.1 of the DSP (Exhibit B1, Tab 1, Schedule 1) and then the common corporate costs are compiled and layered onto the investment plan. The result is run through Hydro One's business plan models to determine revenue requirement and average rate increases, and the written business plan documents are prepared and reviewed for presentation to Hydro One's Executive Leadership Team followed by its Board of Directors. The Dx Business Plan forms the basis for this Application. Supporting evidence for the Application is prepared based on the approved business plan.

Please see Exhibit I-24-SEC-36 for a timeline for the process.

Please see Exhibit I-3-SEC-1 for budget guidance documents.

Witness: LOPEZ Chris

Consumers Council of Canada Interrogatory # 8

Issue:

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Reference:

A-03-02 Page 8 Table 3

Interrogatory:

Based on the proposed revenue requirement figures set out in Table 3 please confirm that HON is seeking to recover (on average) approximately an additional $52 million per year from its customers over the plan term relative to current rates. Please provide the total amount per year (increases relative to current rates) inclusive of the deferral and variance account amounts.

Response:

As outlined in the table below, Hydro One is seeking to recover (on average) an additional $50.7 million per year from its customers over the plan term relative to current rates inclusive of deferral and variance account amounts. Hydro One notes that the appropriate proposed revenue requirement figures for this calculation are provided in the application update filed in Exhibit Q, Tab 1, Schedule 1.

Year	Revenue Requirement (A) **	DVA Disposition (B) ***	Total (C = A+B)	Change in Total (C) Relative to Prior Year
2017	$ 1,467.58	$ 11.08	$ 1,478.66	-
2018	$ 1,517.11	$ 6.18	$ 1,523.29	$ 44.63
2019	$ 1,564.06	$ 6.18	$ 1,570.24	$ 46.95
2020	$ 1,610.67	$ 6.18	$ 1,616.85	$ 46.60
2021	$ 1,684.41	$ 6.18	$ 1,690.59	$ 73.75
2022	$ 1,725.87	$ 6.18	$ 1,732.05	$ 41.46
			Average Annual Change	$ 50.68

* All dollar figures are in millions.

** Revenue requirements reflect values in Exhibit Q, Tab 1, Schedule 1.

*** DVA refers to deferral and variance account balances for disposition.

Witness: D'ANDREA Frank

OEB Staff Interrogatory # 26

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01 Page: 5 – PSE TFP study

Figure 2 shows the estimated annual TFP for the Ontario electricity distribution sector as estimated by PSE. Following the chart, PSE states:

> *"The Ontario industry had four consecutive years of TFP growth from 2002 to 2006. Then mixed results from 2007 to 2010. Since 2010, Ontario has experienced five consecutive years of TFP declines. Some of this drop is possibly due to the economic downturn. Other factors, such as aging infrastructure, increasing unmeasured outputs (e.g. environmental, regulatory, safety, customer service), and the general slowing of output growth, are also possibilities."*

While the issue of aging infrastructure is true in some instances, the Ontario electricity distribution sector has had significant capital investments in new technologies such as smart meters and associated communications technologies. Following restructuring, market opening and the legislated rate freeze, there have been major capital programs undertaken by most distributors from 2008 onwards. While there was the economic downturn in late 2008, the recovery from 2009 onwards has been positive and prolonged, even if growth is gradual. However, many distributors have seen growth in customers or connections, even if average energy consumption and demand per customer/connection is trending downwards, due, in part, to changes in the economy, technology and conservation initiatives.

Interrogatory:

As PSE has done work in the Ontario electricity sector, both for the OEB and for electricity distributors, it would have a comprehensive understanding of the Ontario electricity sector.

a) Can PSE provide a more detailed and fuller explanation for what factors are driving the negative TFP for the Ontario electricity distribution sector after 2009?

Witness: PSE

b) Could these results be also reflective of data and data adjustments that PSE made, particularly subsequent to 2012 (i.e., PEG's TFP study as done for EB-2010-0379), in conducting its analysis?

Response:

a) Please see pp.12-13 (Section 3.2) of Exhibit A, Tab 3, Schedule 2, Attachment 1, Total Factor Productivity Study of the Electric Distribution Functions of Hydro One and the Ontario Industry, for PSE's explanation of some of the possible factors that could contribute to negative TFP growth. The Productivity Report states on page 13: "Unfortunately, it is impossible to empirically adjust for all of the underlying causes of observed TFP trends. PSE addressed the safety and reliability metrics to move the TFP trends closer to being true measures of performance." This issue also arose in 4GIR and no consultant or party was able to fully explain the negative TFP growth. PSE has put forth the reliability and safety adjustments to partially explain the negative TFP growth for Hydro One. The use of the EUCPI also has the impact of creating a more negative industry TFP trend. Substituting the EUCPI for a construction cost index that does not include financing costs would likely increase measured TFP trends. This substitution would also have the off-setting impact of increasing the measured industry input price inflation and should be accompanied by an input price differential factor if implemented in the productivity factor. Please see page 25 of the Productivity Report where PSE addressed this issue.

b) If by "these results" the question is referring to the negative industry TFP trend after 2009, the first thing to say is that the PSE adjustments after 2012 had nothing to do with the substantial negative growth rates found in 2011 and 2012. After 2012, PSE only made changes to the 4GIR data where the same data or index used was not available. The EUCPI was discontinued, so we escalated the construct cost index by the Handy-Whitman index for only the year 2015. The capital addition data used the RRR data, and the OM&A used PEG's same definition for TFP in 4GIR. In PEG's benchmarking updates for 2014, 2015, and 2016 the smart meter expenses equalled zero and might not have been updated. If metering expenses had been fully excluded, this would have raised the industry TFP for 2013-2015. However, the beginning years of the sample include metering expenses, and a full exclusion of ongoing metering costs will create a biased TFP trend. According to the Ontario Energy Board's Monthly Report in October 2012, as of August 31, 2012, 99% of the smart meters for RPP eligible customers had been installed.[1]

[1] https://www.oeb.ca/oeb/_Documents/SMdeployment/Monthly_Monitoring_Report_August2012.pdf

Witness: PSE

For the years 2013-2015 the OM&A and capital additions may include smart meter expenses that are embedded in the capital additions. However, the Ontario TFP trend calculated in 4GIR already excludes a large portion of the smart meter implementation expenses. The largest additions occurred prior to 2013. Since by the end of 2012, 99% of RPP eligible customers had their smart meters installed. At some point the ongoing costs of metering customers, needs to enter into the TFP calculations, otherwise it ceases to become a "total" factor productivity study. Any operational efficiencies from smart meters are likely being captured within the TFP trends through reduced OM&A spending, thus, the ongoing metering costs should also be included. Otherwise, a bias is being created where ongoing metering costs are included in the beginning of the sample period yet excluded in the last part.

Witness: PSE

Vulnerable Energy Consumers Coalition Interrogatory # 8

Issue:

Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:

A-03-02-01

Exhibit A, Tab 3, Schedule 1 7 Exhibit A-3-2, Attachment 1 (PSE TFP Study)

Interrogatory:

a) In its TFP Report dated November 4, 2016 "PSE recommends setting the stretch factor no higher than 0.6%" (page 5). Is the only difference between this recommendation and that made in the May 18, 2017 Report the addition analysis drawn from adding data from U.S. utilities? If not please list all other factors which caused PSE to change its November 16, 2016 recommendation.

b) Please list the methodological differences as between the PSE Benchmarking Study and the PEG July 2017 Benchmark Study provided to the Ontario Energy Board.

c) Does Hydro dispute any of the conclusions in the 2017 PEG Study?

d) Please comment on the sensitivity of the model to adding or subtracting years of data. Specifically, what sensitivity analysis was undertaken to PSE to understand the stability of the model?

Response:

a) The difference was that when the TFP Report came out in November, 4, 2016, PSE had not yet conducted the total cost benchmarking research for Hydro One. On that same page 5 of the TFP report PSE states: "PSE is of the opinion that accurate total cost benchmarking is the best approach to setting stretch factors." Once PSE conducted the total cost benchmarking subsequent to that report, the stretch factor was based on the total cost benchmarking results.

b) There are not any major methodological differences, in PSE's opinion. Three of the most prominent differences in key items within the basic methodological framework are: (1) the different datasets used, (2) the included variables to explain total cost values, and (3) the cost definitions are slightly different to assure consistency with the different datasets.

Witness: PSE

c) The dataset used in the 2017 PEG Study does not allow for an accurate benchmarking study of Hydro One. The dataset used in the 2017 PEG Study is an Ontario-only dataset. Hydro One's service territory covers around 75% of Ontario, and when the utility to be studied comprises such a large portion of the dataset to be benchmarked, the results are not accurate.

d) Hydro One's large size relative to other Ontario utilities means that it is an extreme outlier within the Ontario-only sample. This is true both in terms of size and customer density. Explanatory variables estimated within an econometric model are most accurate at the mean (or average) of the dataset. They then become less accurate as observations move away from that mean value. Furthermore, there are no observations that "encompass" Hydro One in the Ontario dataset—in other words, there are no distributors larger than Hydro One and no distributors with the rural characteristics. Thus, when an Ontario-only dataset is used, it significantly reduces the total cost model's accuracy, since the parameter estimates have no observations close to the variable values of Hydro One.

e) The benchmarking results for Hydro One will change if years are excluded from the sample period. PSE used 2002 as the start year because this is the first feasible start year for Hydro One. PSE did not test out other start years in our research. In response to this interrogatory, PSE tested the sensitivity by excluding the first three years of the sample period from the dataset. This produced a dataset from 2005 to 2015. Hydro One's benchmark result in 2016 changed from +21.6% to +16.2%. Both of these results are within the stretch factor threshold, indicating a 0.45% stretch factor.

Witness: PSE

2.2 CAPITAL IN-SERVICE VARIANCE ACCOUNT (CISVA)

A CISVA is a mechanism to track the difference between the revenue requirement associated with the actual in-service capital additions during a rate year and the revenue requirement associated with the OEB-approved in-service capital additions for that year. If in-service additions in a test year are less than the OEB-approved level, the balance of the account would be negative and refunded to customers in a future rate-setting period. If actual in-service capital additions are equal or greater than the OEB-approved level in the test year, no entry would be recorded in the account.

Hydro One is proposing a CISVA with the following key features:

(i) Purpose is to track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;

(ii) For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and

(iii) At the end of the five-year term of the Custom IR Plan, in 2023, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;

- Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
- Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from ratepayers

Witness: Oded Hubert

Energy Probe Research Foundation Interrogatory # 11

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02 Page: 10

Interrogatory:

a) Please explain the method Hydro One proposes to use in tracking "verifiable productivity gains" during the Custom IR term.

b) Please provide a numerical example using hypothetical numbers.

Response:

a) The method used to track verifiable productivity savings is described in part (b) of Hydro One's response to Exhibit I- 25-Staff-123.

b) A numerical example is provided below.

In Service Additions Target (includes embedded productivity) (A)	$100
Actual In Service Additions Achieved (B)	$ 96
Incremental verifiable Capital-related productivity (C)	$ 3
Deemed In Service Additions (D) → (B) + (C)	$ 99
In Service Ratio (D) / (A)	99%

Verifiable capital-related productivity savings reflect the sum of capital productivity savings and the capital allocated portion of productivity savings associated with Common Corporate costs. Incremental verifiable capital-related productivity savings reflect verifiable productivity savings above amounts shown in Exhibit I- 25-Staff-123.

Witness: D'ANDREA Frank

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

OEB Staff Interrogatory # 22

Issue:
Issue 8: Is the proposed industry-specific inflation factor, and the proposed custom productivity factor, appropriate?

Reference:
A-03-02 Page: 4 - Stretch Factor
Hydro One states:

> *"The Productivity Factor used in the RCI will not be updated annually over the 2019 to 2022 portion of the Custom IR term. In its total cost benchmarking study, PSE conducted a forward-looking analysis using Hydro One's forecast costs for 2018-2022. This analysis concluded that Hydro One's forecast costs are likely to continue to support a 0.45% stretch factor ranking throughout the incentive rate-setting period."*

Interrogatory:

a) Under the OEB's 2nd and 3rd Generation IRM plans and the current Price Cap IR framework, a utility's ranking for assigning the stretch factor annually depends not only on its performance, but also on the performance of all other Ontario distributors, to gauge how performance in the industry as a whole is changing.

   While PSE may have had Hydro One's forecasted costs, it would not have forecasted costs for other electricity distributors in Ontario, or for other peer utilities in North America. On what basis and with what confidence have PSE and Hydro One concluded that Hydro One's performance will continue to warrant a 0.45% stretch factor throughout the period absent forecasts of how other firms costs are also expected to change in the test period?

b) Under an assumption that the annual benchmarking and assignment of a stretch factor as is currently conducted under direction of the OEB continues throughout the 5-year test period, why should Hydro One's stretch factor not be updated annually?

Witness: PSE

Response:

a) The benchmarking scores that currently warrant a 0.45% stretch factor based on the forecasted data were constructed using costs that assume full funding of Hydro One's application. PSE agrees that under the current and past IRM plans, the industry performance can impact the benchmarking scores of the studied utility. To the extent the overall industry performance changes, then the benchmarking score would be impacted. The stretch factor may be impacted due to this, however, it most likely would not be a large enough impact to change the stretch factor cohort. PSE's approach uses the historically available data as the foundation for the forecasted results. Implicit in that is an assumption that the industry performance remains unchanged compared to its historical performance. Forecasting the benchmarks using historical sample data is the best available method to provide stakeholders with accurate total cost benchmarking scores during the course of this application.

b) The benchmarking model and dataset that is currently being updated annually should not be applied to Hydro One and used as the basis of their stretch factor. Hydro One is an extreme outlier in both size and density in the Ontario-only dataset. To accurately benchmark Hydro One, the PSE dataset and variables should be used. Conducting an annual benchmarking review within a custom IR plan would create increased ongoing regulatory effort for the benefit of only one distributor, albeit a large one. This contrasts with the cited IRM situation, where the ongoing benefit is to numerous distributors within the industry. Accurately benchmarking Hydro One requires a different sample than most other Ontario distributors. It may make sense to limit this activity to once every five years rather than conduct the analysis annually. There would likely be a low chance of a different stretch factor in each year. However, PSE does believe that conducting the benchmarking research annually would provide more accurate results. This is especially true if the OEB does not fully fund Hydro One's spending request. In that case, the benchmarking results shown in part a) above should be modified to reflect those potentially lower spending levels in determining Hydro One's stretch factor.

Witness: PSE

Ontario Energy Board

Ontario

EB-2010-0379

Report of the Board

Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors

Issued on November 21, 2013 and as corrected on December 4, 2013

Appendix D: 2014 Stretch Factor Assignments

Group I	Group II	Group III	Group IV	Group V
Stretch Factor of 0.0%	**Stretch factor of 0.15%**	**Stretch factor of 0.3%**	**Stretch Factor of 0.45%**	**Stretch Factor of 0.6%**
• E.L.K. Energy Inc. • Halton Hills Hydro Inc. • Hearst Power Distribution Company Limited • Hydro Hawkesbury Inc. • Northern Ontario Wires Inc. • Wasaga Distribution Inc.	• Cooperative Hydro Embrun Inc. • Enersource Hydro Mississauga Inc. • Entegrus Powerlines • Espanola Regional Hydro Distribution Corporation • Essex Powerlines Corporation • Grimsby Power Incorporated • Haldimand County Hydro Inc. • Horizon Utilities Corporation • Kitchener-Wilmot Hydro Inc. • Lakefront Utilities Inc. • London Hydro Inc. • Newmarket-Tay Power Distribution Ltd. • Oshawa PUC Networks Inc. • Rideau St. Lawrence Distribution Inc. • Welland Hydro-Electric System Corp.	• Bluewater Power Distribution Corporation • Brantford Power Inc. • Burlington Hydro Inc. • Cambridge and North Dumfries Hydro Inc. • Centre Wellington Hydro Ltd. • Collus Power Corporation • Greater Sudbury Hydro Inc. • Guelph Hydro Electric Systems Inc. • Hydro 2000 Inc. • Hydro One Brampton Networks Inc. • Hydro Ottawa Limited • Innisfil Hydro Distribution Systems Limited • Kenora Hydro Electric Corporation Ltd. • Kingston Hydro Corporation • Lakeland Power Distribution Ltd. • Milton Hydro Distribution Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Norfolk Power Distribution Inc. • North Bay Hydro Distribution Limited • Orangeville Hydro Ltd • Orillia Power Distribution Corporation • Ottawa River Power Corporation • Parry Sound Power Corporation • PowerStream Inc. • PUC Distribution Inc. • Sioux Lookout Hydro Inc. • St. Thomas Energy Inc. • Thunder Bay Hydro Electricity Distribution Inc. • Veridian Connections Inc. • Waterloo North Hydro Inc. • Westario Power Inc. • Whitby Hydro Electric Corporation	• Atikokan Hydro Inc. • Brant County Power Inc. • Canadian Niagara Power Inc. • Chapleau Public Utilities Corporation • Enwin Utilities Ltd. • Erie Thames Powerlines Corporation • Festival Hydro Inc. • Fort Frances Power Corporation • Midland Power Utility Corporation • Oakville Hydro Electricity Distribution Inc. • Peterborough Distribution Incorporated • Renfrew Hydro Inc. • Tillsonburg Hydro Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc.	• Algoma Power Inc. • Hydro One Networks Inc. • Toronto Hydro-Electric System Limited • Woodstock Hydro Services Inc.

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)

Witness: Oded Hubert

Energy Probe Research Foundation Interrogatory # 9

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-01 Page: 22 Table 6

Interrogatory:

Preamble: In Hydro One's previous distribution rate application – EB-2013-0416, 2015-2019 rates – the utility estimated that it would achieve more than $100 million annually in productivity savings between 2015 and 2019. When the test year, 2014, was included, those savings amounted to more than $728 million in savings.

a) Can Hydro One provide an update on the forecasted savings from its previous rate application?

b) Are those productivity savings included in this application?

c) Are the savings detailed in Hydro One's current application in addition to those laid out in the previous rate application?

Witness: LOPEZ Chris

School Energy Coalition Interrogatory # 33

Issue:

Issue 21: Does the application adequately account for productivity gains in its forecasts and adequately include expectations for gains relative to external benchmarks?

Reference:

Previous Proceeding
[EB-2013-0416, Exhibit I, Tab 2.03, Schedule 6 VECC 42, p.2]

Interrogatory:

With respect to the productivity forecasts in EB-2013-0416:

a) Please complete the shaded areas on the attached table to show for each productivity initiative the actual annual savings achieved in each year between 2014 and 2016, and any revised forecast savings for each year between 2017 and 2019.
b) Please explain any material variances from between actuals and EB-2013-0416 forecasts, and any revised forecasts and EB-2013-0416 forecasts

Response:

a) Hydro One's productivity plan was reset in 2015 and the associated governance was enhanced at the time of application. Only forward looking initiatives with a direct impact to costs were included in the forward looking plan. Legacy initiatives are no longer individually monitored.

   The initiatives in EB-2013-0416 are legacy initiatives and have been included in the underlying plan assumptions and now form part of regular operations. As a result Hydro One is unable to accurately complete the requested table.

   Hydro One's forward looking productivity plan is described in OEB Staff Interrogatory # 123.

b) Please refer to a), above.

Witness: LOPEZ Chris

School Energy Coalition Interrogatory # 14

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

A-03-02-01 Page: 9 and 22

Interrogatory:

Please confirm that the primary reason for the Hydro One's positive TFP from 2010-2015 is its control of OM&A costs relative to inflation. Please quantify if possible the impact of this factor on the TFP trajectory for this period

Response:

The lower growth in OM&A relative to inflation contributed to the positive TFP by approximately 0.5%. If the OM&A expenses had increased by the OM&A input price inflation rate from 2010 to 2015, then the adjusted TFP becomes 0.0%.

Witness: PSE

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2013-0416/EB-2014-0247

IN THE MATTER OF AN APPLICATION BY

HYDRO ONE NETWORKS INC.

FOR APPROVAL OF DISTRIBUTION RATES FOR 2015 TO 2019

DECISION
March 12, 2015

As is the case with any benchmark comparison, the need for cogent evidence to justify a level of spending or level of service quality is commensurate with its deviation from the level demonstrated by similar distributors. For instance, if a company spends more for a particular service or activity than most other comparable companies, it must provide more evidence for the level of proposed spending than if its level of spending was less than comparable companies. The OEB uses benchmarking as a tool to focus and prioritize its attention on certain costs. Benchmarking increases the efficiency of regulatory oversight. It does not replace the need for substantiating evidence in support of spending levels.

Hydro One did not provide sufficient evidence in support of its proposed compensation spending. The company did not demonstrate that the market requires the level of compensation proposed in order to attract and retain the necessary employees. In the absence of such evidence the OEB will use the market median as a reference point for the percentage of compensation costs that will be included in the rates paid by Hydro One's customers.

As previously stated, in arriving at an appropriate OM&A budget it is critical to ensure that Hydro One has sufficient funds to operate a safe and reliable system. The OEB must balance the ability of Hydro One to perform the work that is necessary to maintain the system and the fairness to its customers in paying for a level of compensation that has not been satisfactorily substantiated. In the absence of evidence indicating that higher levels of compensation are justified, the market median compensation level provides an indication that Hydro One customers are being asked to pay too much for the provision of the service they receive. As noted above, Hydro One indicated that if its compensation level were set at the market median level it would result in a reduction of about $15.4 million per year in OM&A costs.

While the OEB recognizes the progress that Hydro One has made over the last few years in getting closer to the market median, the OEB does not find that it is fair that ratepayers pay for a 10% premium over the market median. The OEB, however, will not disallow the entire 10% premium. Rather, the OEB will require efficiency from Hydro One by disallowing half of that amount from the revenue requirement, or $7.7 million per year, each year for 2015, 2016 and 2017. The OEB still expects Hydro One

OEB Staff Interrogatory # 47

Issue:

Issue 10: Are the program-based cost, productivity and benchmarking studies filed by Hydro One appropriate?

Reference:

B1-01-01 Section 1.5 Page: 2/ Table 17- Productivity Savings

Table 17 shows the detailed productivity savings that Hydro One has estimated for the capital and OM&A programs in its application, by year. Hydro One states that these savings are factored into the capital and OM&A plans.

Interrogatory:

a) Are the savings for Procurement and Administration categorized as capital or OM&A in nature? If mixed please provide a disaggregation.

b) It is easy to see how OM&A productivity savings in 2018 can be factored into the 2018 revenue requirement and hence reflected in 2018 distribution rates to recover that revenue requirement, all else being equal. Similarly, with the forecasted capital budget which is factored into the forecasted rate base for each year, it is easy to see how the capital productivity savings can be factored into each year's revenue requirement. However, Hydro One has proposed that the OM&A component of each year's revenue requirement is adjusted formulaically by inflation-less-productivity for the period 2019-2022.

   Please explain how the expensed productivity savings for 2019-2022 are factored into the revenue requirement derivation so that customers receive the benefits of these savings.

Response:

a) Please see response to Exhibit I-8-Staff-018, part a).

b) Over the course of the IR term (2019-2022), customers will see the benefit of a stable OM&A envelope that is increasing at a rate less than inflation (i.e. inflation minus stretch factor). The identified productivity savings will be used to offset the upwards inflationary cost pressures of other elements of Hydro One's OM&A envelope. Through the Custom IR mechanism, customers will be fully protected and Hydro One will fully bear the cost risk in the event that it does not achieve its forecast productivity savings. If Hydro One is able to materially exceed its expected productivity savings, customers will share in the benefit of the reduced costs through the Earnings Sharing Mechanism proposed in Exhibit A, Tab 3, Schedule 2. When Hydro One rebases in 2023, its new OM&A envelope will be lower than it would otherwise have been and any remaining impact of the achieved productivity savings will be fully shared with rate payers.

Witness: LOPEZ Chris and D'ANDREA Frank

Energy Probe Research Foundation Interrogatory # 3

Issue:
Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Reference:
N/A

Interrogatory:
Please file the bill impacts on the various rate classes if the Board were to approve Hydro One's application as is, with an effective date of January 2019. Energy Probe is most interested in seeing the bill impacts in 2019 that will include a rate rider for the collection of 2018 rates. Please do not include any bill mitigation measures or Fair Hydro Plan rebates.

For R2 customers, please do include the recent increase to the Rural or Remote Rate Protection program.

Response:
If the application was approved as is, but with an effective date of January 1, 2019, the 2019 bill impacts including a rider for recovery of the foregone 2018 revenue requirement would consist of i) the combined 2018 and 2019 bill impacts plus ii) the impact of recovering the forgone revenue in 2019. The 2019 bill impacts for a typical customer in each rate class, consistent with Hydro One's December 17, 2017 update to the evidence would be approximately as shown in the table below. The bill impacts in other years would remain largely unchanged, except for the small impact associated with recovering regulatory asset balances over 4 years instead of 5 years.

Witness: ANDRE Henry

2019 bill impacts assuming 2018 rates are approved as filed, but implemented on January 1, 2019						
Rate Class	**Monthly Consumption (kWh)**	**Monthly Peak (kW)**	**Change in DX Bill ($)**	**Change in DX Bill (%)**	**Change in Total Bill ($)**	**Change in Total Bill (%)**
UR	750		$4.39	13.6%	$10.70	8.2%
R1	750		$8.59	16.6%	$13.90	9.1%
R2	750		$13.65	27.7%	$18.62	12.3%
Seasonal	352		$7.58	12.7%	$9.41	8.6%
GSe	2,000		$21.26	15.1%	$26.99	6.4%
UGe	2,000		$11.44	15.0%	$16.14	4.6%
GSd	36,104	124	$399.66	19.5%	$524.92	7.3%
UGd	50,525	135	$334.70	26.3%	$573.47	7.0%
St Lgt	517		$7.20	13.7%	$10.31	8.5%
Sen Lgt	71		$1.97	17.6%	$2.45	11.7%
USL	364		($0.19)	-0.4%	$0.82	0.9%
DGen	1,328	13	$115.50	47.5%	$140.38	31.0%
ST	1,601,036	3,091	$1,302.02	30.2%	$4,923.91	2.2%

Witness: ANDRE Henry

Building Owners and Managers Association Toronto Interrogatory # 17

Issue:

Issue 4: Are the rate and bill impacts in each customer class in each year in the 2018 to 2022 period reasonable?

Issue 3: Is the overall increase in the distribution revenue requirement from 2018 to 2022 reasonable?

Issue 29: Are the proposed capital expenditures resulting from the Distribution System Plan appropriate, and have they been adequately planned and paced?

Issue 51: Are the revenue-to-cost ratios for all rate classes over the 2018 – 2022 period appropriate?

Reference:

A-03-01

Interrogatory:

a) p2 - Please provide the forecast percentage rate increase for each year over the period 2018 to 2022, commencing with the 2018 rates over existing 2017 rates.

   i. Please provide the derivation underlying calculations of the 4.7% as the 3.0% of the cited at lines 19 and 20.
   ii. Please provide the same data as in (i) for historical years 2017 over 2016, 2016 over 2015, 2015 over 2014, 2014 over 2013, and 2013 over 2012.

b) p23 - What are 2016 Actual Revenue Requirement relative to Board-approved Revenue Requirement?

c) What are the 2017 actual OM&A to date (September 30, 2017)? Extend revenue to date?

d) p5 – Please provide the derivation of the 4.2% reduction in capital expenditures from 2017 Board-approved levels. What is the year to date and current forecast 2017 actual capital expenditures?

Witness: ANDRE Henry

e) Please confirm that for residential customers in 2018, the distribution rate is determined to the extent of 75% by customer charge, which does not vary with electricity consumption on demand.

f) Please show the corresponding bill increases for section **Error! Reference source not ound.** above

__Response:__

a) The forecast percentage rate increase of 4.9% shown in the reference A-03-01 was subsequently updated to 6.1% as shown on page 3 of Exhibit Q-01-01 filed with the Board on December, 21, 2017. The answers below are provided based on Hydro One's current proposal as per Exhibit Q-01-01.

The forecast percentage rate increases are provided in the table below as requested.

2018 increase over 2017	**2019 increase over 2018**	**2020 increase over 2019**	**2021 increase over 2020**	**2022 increase over 2021**
6.1%	3.6%	2.9%	2.4%	2.2%

i. The Derivation of 6.1% is the combined impact of a 3.1% increase in 2018 revenue requirement plus riders and other revenues over the equivalent amounts in 2017, plus a 3.0% increase due to the revenue deficiency associated with rebasing the load forecast in 2018. The calculations are shown in the table below. Details of the revenue deficiency associated with the load forecast impact of 3.0% is provided in the response to Exhibit I-19-BOMA-19 part h).

	2017	**2018**
Revenue Requirement	1,467.6	1,517.1
Rate Riders	11.1	6.2
Other revenue impacts	(52.7)	(53.6)
Rates Revenue Requirement	**1,426.0**	**1,469.7**
Rates Increase over 2017		3.1%
Load Impact		3.0%
Rate Increase Required		6.1%

Witness: ANDRE Henry

ii. Please see the table below for the information requested.

	2013 over 2012	2014 over 2013	2015 over 2014	2016 over 2015	2017 over 2016
Change in Revenue	1.1%	3.5%	11.2%	6.3%	0.4%
Load Impact	0% *	0% *	0.7%	-0.5%	-0.8%
Total	**1.1%**	**3.5%**	**11.9%**	**5.8%**	**-0.4%**

* IRM years – no changes to load forecast.

b) Please refer to the following exhibits where actuals have been filed. For 2016 actual OM&A, please refer to Exhibit C1, Tab 1, Schedule 1. For actual depreciation expense, please refer to C1, Tab 6, Schedule 1. For actual calculation of utility income taxes, please refer to Exhibit C1, Tab 7, Schedule 2, Attachment 3. For actual external revenues, please refer to Exhibit E1, Tab 1, Schedule 2.

c) While this interrogatory requests "the actual OM&A to date (September 30, 2017), Hydro One proposes to provide year end actual 2017 OM&A when available, consistent with other requests.

d) The 4.2% reduction in capital expenditures is captured in the 2017 Bridge Variance column of Exhibit A-03-01 (Table 9). 2017 actuals will be made available at a later date.

e) No that is not correct. As shown in the evidence at Exhibit H1, Tab 1, Schedule 2, page 1, the fixed customer charges collected from the residential classes in 2018 account for 83% of UR class revenue, 65% of the R1 class revenue, 68% of the R2 class revenue, and 66% of the Seasonal class revenue.

f) The bill increases for each rate class corresponding with the proposed revenue requirement and load forecast for all years of this application are provided in Table 1 of Exhibit H1, Tab 4, Schedule 1 of the evidence.

Witness: ANDRE Henry

Building Owners and Managers Association Toronto Interrogatory # 42

Issue:

Issue 1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Reference:

A-03-01-03 Appendix A Page: 4

Interrogatory:

a) Please describe the backlog of preventative maintenance, the plan to deal with it, the time that will take, the costs of doing so, and the cost of keeping ongoing maintenance schedule current. Are the costs in the five year budget and distribution investment plan?

b) Please provide a copy of the Work Governance Agreement, referred to.

Response:

a) Hydro One Distribution does not consider there to be a backlog of preventive maintenance work.

b) This request pertains to Hydro One Transmission business not to Hydro One Distribution, and therefore not relevant to the distribution rate filing.

Witness: GARZOUZI Lyla

OEB Staff Interrogatory # 9

Issue:
Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:
Executive Presentation Day Transcript, page 18 and page 44
Exhibit C1/Tab 1/Schedule 5, pg 13, Table 11: Operational Effectiveness Outcomes

Interrogatory:
As noted above, Hydro One witnesses mention the bill redesign and its launch in late 2017. Table 11 indicates that the redesign "will make it easier for customers to understand their bill and increase their understanding of their electricity consumption."

a) The Hydro One witness mentioned that 40% of customers found that the current bill was confusing. What was the source of this statement?

b) Were there additional reasons for pursuing a bill redesign?

c) Please summarize the changes made to the bill design and why each specific change was made.

d) What was the cost of this bill redesign and are any of the costs of this project proposed to be recovered in 2018 rates?

e) What are the benefits expected from this bill redesign? Is customer satisfaction expected to improve? If so, by what amount? Are call volumes expected to be lower? Again by what amount? Would this lead to lower staffing and other costs and if so, to what extent?

f) Have bills also been redesigned for General Service and Large User customers? If so, what was the rational for this redesign and what are the benefits expected?

g) As Hydro One has shared this bill redesign with other distributors, what is the status of the bill redesign project in the distribution sector?

Witness: PUGLIESE Ferio

h) After the 2017 bill redesign completed in 2017, why is Hydro One planning another bill redesign for 2021/2022, as shown at ISD GP-29 (Customer Service Billing Investments)? What additional features are planned in the 2021/2022 redesign not already in 2017 redesign?

Response:

a) Hydro One conducts surveys on a regular basis across various customer segments to gain an understanding of the key drivers impacting customer satisfaction. All research is conducted by independent experts, thereby ensuring results are unbiased. The referenced statistic is based on results from the bi-annual Residential and Small Business survey.

b) Hydro One redesigned the bill in order to:
   - improve customer comprehension of information presented on the bill;
   - improve information retention by customers; and
   - replace vendor unsupported/antiquated bill print tools and applications.

c) Please refer to Exhibit I-2-Staff-8.

d) The cost of the Bill Redesign in 2017 was $9 million, broken down as follows: actual bill graphical design (1%); customer and behavioural science research (6%); replacement of out-dated bill print hardware and applications (26%); system design and testing (54%); and customer communication, migration and call centre staff training (13%). There will be no impact to 2018 rates as a result of this initiative.

e) Hydro One expects increased customer comprehension of their bill and electricity consumption, leading to improved customer satisfaction with service delivery. The redesigned bill will also encourage energy conservation by providing customers information on how they can manage their usage better to take advantage of off-peak rates. Furthermore, the new modular design will allow Hydro One to implement modifications faster to meet future regulatory and customer need driven changes.

   It is anticipated that with the new design, customers comprehension about their electricity consumption will increase, thereby reducing the number of calls to the contact centre. Since the new bill has not been fully rolled out yet, Hydro One is unable to quantify the potential reductions.

f) Bills for demand and interval billed customers and generator statements have not been redesigned as part of this initiative. However customer feedback has identified numerous needs for improvement, including items such as enhanced on-line access to statements such as more detailed supporting data and calculations and statements that are more flexible to better reflect the site specific supply and billing parameter configurations.

g) Hydro One has shared the customer insights and bill design with the Electricity Distributors Association, numerous local distribution companies, and the Ministry of Energy as part of their initiative on updating existing bill format regulations. The Ministry of Energy is contemplating a working group to update bill format regulations in an effort to improve bill comprehension and satisfaction. It is anticipated that Ministry efforts will result in the need for other local distribution companies to make updates to their bill designs.

h) The majority of the funding outlined in the Investment Summary Document GP-29 is required to reengineer processes and replace antiquated tools and applications that support non-energy billing, including: invoicing, collections, and customer service such as providing customers electronic bills and self-service options. The remaining funds are earmarked for the implementation a new bill design to meet the needs of commercial and industrial customers.

OEB Staff Interrogatory # 7

Issue:

Issue 2: Has Hydro One adequately responded to the customer concerns expressed in the Community Meetings held for this application?

Reference:

Executive Presentation Day Transcript, page 49-50
Exhibit B/Part B/ISD GP-31 (Prepaid Meters)

Interrogatory:

At the Presentation Day, Mr. Pugliese indicated that Hydro One would never force the pre-paid meter option on any customer and that some customers have requested the pre-paid meter option and others have shown a preference for the load limiter option. At Exhibit B, Hydro One has indicated that it plans to commit $6.1 million in capital to a pre-paid meter project in 2022.

a) Please indicate the degree to which customers prefer the prepaid meter and load limiter options, and in particular:
   i. How many customers have requested prepaid meters? Were these requests unsolicited? What were the circumstances under which the requests were made?
   ii. How many customers have provided unsolicited requests to have a load limiters installed?
   iii. How many customers have provided unsolicited requests to keep a load limiter in lieu of complete reconnection?
   iv. What is Hydro One's current policy on the use of load limiters? Would this policy change under the proposed pre-paid meter program?

b) How will the planned prepaid meter program work in order to allow alternate arrangements to be made for payments (e.g. arrears management plans)?

c) Currently the LEAP program is designed to help pay arrears and maintain connection. It is generally accessed once the consumer receives a disconnection notice. If the consumer is on pre-paid meter service, how would the LEAP be used to provide credits to keep the electricity on?

d) Assuming that the meter would automatically disconnect when the credits run out, how would this be consistent with the disconnection requirements in the various codes and any legislative and/or regulatory restrictions on disconnections in the winter months?

Witness: PUGLIESE Ferio

e) How would this program work for special situations such as customers that have specific medical needs for electricity service?

f) What is the rationale for introducing the pre-paid meter program in 2022?

g) Section 53.16(1) of the Electricity Act in association with O. Reg. 525/06 states that when a distributor replaces an existing meter for residential or general service customers, the meter must meet the Functional Specification for Advanced Metering Infrastructure. Will these pre-paid meters meet the "functional specifications"? If not, how will Hydro One resolve this conflict?

h) Section 3.4 of the Standard Supply Service Code states that customers with eligible time-of-use meters must be charged using time-of-use pricing. Will these pre-paid meters be able to charge customers based on time-of-use pricing? If not, how will Hydro One resolve this conflict?

i) If pre-paid meters were to charge based on time-of-use, how would customers reasonably be able to calculate the amount of pre-paid credit required and/or available to cover a specific period given changes in pricing, use and timing?

j) Would pre-paid meters be able to shift between pre-paid mode and "regular" mode to ensure a consumer was not effectively disconnected during winter if unable to purchase new credits?

k) How would consumers "purchase" credits for pre-paid meters? If it is internet based, has Hydro One taken into consideration the complexities and service issues associated with internet access in remote communities? If consumers are able to purchase via credit card, has Hydro One taken into account the limitations on access to credit cards for lower income households?

l) How would fixed charges, such as the monthly delivery fee, be billed for pre-paid meter customers? If a pre-paid meter customer did not use any electricity in the month, would they still be charged a monthly delivery fee?

m) How would OESP and/or any other similar support programs be applied for customers with pre-paid meters?

Witness: PUGLIESE Ferio

e) In advance of the pre-paid meter deployment in 2022, Hydro One will create a vulnerability check as part of the eligibility assessment in order to determine if a pre-paid meter is in the best interest of the customer and their specific circumstances, after exploring other options.

f) Hydro One plans on introducing pre-paid metering in 2022 to ensure Hydro One has enough time to develop appropriate policies and procedures, complete field testing, and secure appropriate equipment and software.

g) Refer to part b).

h) Refer to part b).

i) Time-of-use customers with a pre-paid meter will continue to have access to tools that predict electricity usage and consumption patterns, including the time-of-use portal, high usage alerts, budget billing, and CDM.

j) Refer to part b).

k) Hydro One customers with pre-paid meters will have the same payment options available to them as non-pre-paid metered customers, including: bank, internet banking, telephone, credit card, etc.

l) Refer to part b).

m) Refer to part b).

n) In advance of the pre-paid meter deployment in 2022, Hydro One intends to complete a detailed risk assessment, including a review of all policies, soliciting customer input and feedback, and appropriately engaging with stakeholders.

Witness: PUGLIESE Ferio

ONTARIO ENERGY BOARD

Rules of Practice and Procedure
(Revised November 16, 2006, July 14, 2008, October 13, 2011, January 9, 2012, January 17, 2013, April 24, 2014 and October 28, 2016)

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knowledge of the person making the affidavit unless the facts are clearly stated to be based on the information and belief of the person making the affidavit.

12.02 Where a statement is made on information and belief, the source of the information and the grounds on which the belief is based shall be set out in the affidavit.

12.03 An exhibit that is referred to in an affidavit shall be marked as such by the person taking the affidavit, and the exhibit shall be attached to and filed with the affidavit.

12.04 The Board may require the whole or any part of a document filed to be verified by affidavit.

13. Written Evidence

13.01 Other than oral evidence given at the hearing, where a party intends to submit evidence, or is required to do so by the Board, the evidence shall be in writing and in a form approved by the Board.

13.02 The written evidence shall include a statement of the qualifications of the person who prepared the evidence or under whose direction or control the evidence was prepared.

13.03 Where a party is unable to submit written evidence as directed by the Board, the party shall:

(a) file such written evidence as is available at that time;

(b) identify the balance of the evidence to be filed; and

(c) state when the balance of the evidence will be filed.

13A. Expert Evidence

13A.01 A party may engage, and two or more parties may jointly engage, one or more experts to give evidence in a proceeding on issues that are relevant to the expert's area of expertise.

13A.02 An expert shall assist the Board impartially by giving evidence that is fair and objective.

13A.03 An expert's evidence shall, at a minimum, include the following:

(a) the expert's name, business name and address, and general area of expertise;

(b) the expert's qualifications, including the expert's relevant educational and professional experience in respect of each issue in the proceeding to which the expert's evidence relates;

(c) the instructions provided to the expert in relation to the proceeding and, where applicable, to each issue in the proceeding to which the expert's evidence relates;

(d) the specific information upon which the expert's evidence is based, including a description of any factual assumptions made and research conducted, and a list of the documents relied on by the expert in preparing the evidence; and

(e) in the case of evidence that is provided in response to another expert's evidence, a summary of the points of agreement and disagreement with the other expert's evidence.

(f) an acknowledgement of the expert's duty to the Board in **Form A** to these Rules, signed by the expert.

13A.04 In a proceeding where two or more parties have engaged experts, the Board may require two or more of the experts to:

(a) in advance of the hearing, confer with each other for the purposes of, among others, narrowing issues, identifying the points on which their views differ and are in agreement, and preparing a joint written statement to be admissible as evidence at the hearing; and

(b) at the hearing, appear together as a concurrent expert panel for the purposes of, among others, answering questions from the Board and others as permitted by the Board, and providing comments on the views of another expert on the same panel.

13A.05 The activities referred to in **Rule 13A.04** shall be conducted in accordance with such directions as may be given by the Board, including as to:

(a) scope and timing;

(b) the involvement of any expert engaged by the Board;

(c) the costs associated with the conduct of the activities;

(d) the attendance or non-attendance of counsel for the parties, or of other persons, in respect of the activities referred to in paragraph (a) of **Rule 13A.04**; and

(e) any issues in relation to confidentiality.

13A.06 A party that engages an expert shall ensure that the expert is made aware of, and has agreed to accept, the responsibilities that are or may be imposed on the expert as set out in this **Rule 13A** and **Form A**.

14. Disclosure

14.01 A party who intends to rely on or refer to any document that has not already been filed in a proceeding shall file and serve the document 24 hours before using it in the proceeding, unless the Board directs otherwise.

14.02 Any party who fails to comply with **Rule 14.01** shall not put the document in evidence or use it in the cross-examination of a witness, unless the Board otherwise directs.

14.03 Where the good character, propriety of conduct or competence of a party is an issue in the proceeding, the party is entitled to be furnished with reasonable information of any allegations at least 15 calendar days prior to the hearing.

PART III - PROCEEDINGS

15. Commencement of Proceedings

FORM A

Proceeding:..........................

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is ....(*name*). I live at .... (*city*), in the .... (*province/state*) of ....

2. I have been engaged by or on behalf of .... (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:

   (a) to provide opinion evidence that is fair, objective and non-partisan;

   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and

   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date ....

____

Signature