2017 and 2018 TRANSMISSION COST OF SERVICE APPLICATION
EB-2016-0160

Hydro One Networks Inc.

Transmission

OEB STAFF SUBMISSION

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Table of Contents

Introduction

On May 31, 2016, Hydro One Networks Inc. (Hydro One) applied for approval of its 2017 and 2018 transmission revenue requirements to be used to determine the 2017 and 2018 Uniform Transmission Rates (UTR) effective January 1 of each year.

In this application, Hydro One's main approval requests were: a rates revenue requirement of $1,487.4 million for 2017 and $1,558.4 million for 2018; charge determinants by rate pool to determine the UTRs effective January 1, 2017; a proposed performance scorecard; the continuation of certain regulatory accounts and the disposition of regulatory deferral and variance accounts with a net credit balance of $95.6 million effective January 1, 2017 (over a 2 year period).

The proposed revenue requirements reflect a year-over-year increase of 0.5% for 2017 versus 2016 approved levels and 4.8% for 2018 over 2017.

The increase in the total bill for a Hydro One general service energy (2000 kWh/month) customer was estimated to be 0.1% in 2017 and 0.2% in 2018. As for the impact on residential customers, for a Hydro One medium density residential (750 kWh/month) customer, the estimated bill increase was 0.1% in 2017 and 0.2% in 2018. The estimated bill impact for transmission connected-customers was 0.2% in 2017 and 0.4 % in 2018 (assuming that transmission represents 8.3% of the average transmission-connected customer's total bill).

These are OEB staff's submissions on Hydro One's application. The submission addresses the issues before the OEB in this proceeding under main topic headings of the Issues List, rather than addressing the issues individually. If a specific issue is not mentioned, staff has no concerns with Hydro One's proposal and has no submissions on that issue.

Summary of the Application

As noted above, Hydro One requested approval for a number of specific elements in the application, including two key areas for each of the test years: the applied-for increase in total revenue requirement and the load forecast for each year. These are the key inputs used to calculate the UTRs for 2017 and 2018.

The increase in revenue requirement from the approved 2016 year was largely attributable to the impact of rate base growth, with an increase in depreciation expense and a resultant higher return on capital amount. Higher income taxes and lower external revenues also contributed to the increased revenue requirement but these were partially offset by a lower cost of debt and return on equity, lower OM&A costs, increased regulatory account disposition, and a higher export revenue credit.

The load forecast as applied-for shows a reduction in load of 2.6% in 2017 and no load change for 2018.

In its application, Hydro One outlined its strategic goals, values and objectives focusing on its new executive leadership and Board of Directors. Hydro One stressed that it was committed to building a stronger performance management culture and achieving excellence in execution in all aspects of the company's work. These themes, as well as the impact of the partial privatization of Hydro One, which began with the Initial Public Offering (IPO) of November 2015, were explored at the Presentation Day and during the oral hearing.

Hydro One indicated its view that the principles of the OEB's *Renewed Regulatory Framework for Electricity Distributors* (RRFE) are consistent and directly aligned with Hydro One's aspirations. It maintained that its key areas of focus include ensuring that transmission services, capital program execution, and customer operations are more efficient and effective, enhancing the internal performance management culture, and strengthening relationships with key stakeholders.

Hydro One also filed its Transmission System Plan (TSP) which included evidence of its efforts at customer engagement and needs assessment. Hydro One also introduced its Reliability Risk Model, which produces a probabilistic calculation based on asset demographics and the historical relationship between asset age and the occurrence of failure.

Hydro One also filed a Total Cost Benchmarking study as agreed to in its last transmission rates case.[1]

In developing its related investment plan, Hydro One assumed 2.0% annual inflation and cost escalators for construction and OM&A expense growth of 2.3% and 1.3%, in 2017 and 2.5% and 1.6% in 2018, respectively.

[1] EB-2014-0140

Transmission System Plan and Capital Expenditures

Hydro One's TSP proposes capital expenditures of $1,076.1million and $1,122.2 million in 2017 and 2018, respectively.[2] The TSP describes the processes developed and employed by Hydro One to create its capital investment plans.

Hydro One develops its investment plan, or capital envelope, using its Investment Planning Process.[3] During the planning process, Hydro One assesses needs, develops alternatives to meet those needs, and chooses an alternative as the preferred way to meet each need. Hydro One noted that it optimizes its investments and incorporates feedback from internal stakeholders and customers.

The application describes that Hydro One determines its system needs from several sources:[4]

1. The needs and preferences of customers
2. The regional planning process
3. Assets needs as determined by:
    a. Hydro One's approach to asset management, which is informed by Hydro One's new system Reliability Risk Model
    b. The Asset Risk Assessment methodology that Hydro One uses in determining which assets are investment candidates
    c. Hydro One's analyses of the assets that require investment based on asset condition and performance.

Once needs are determined, Hydro One's engineers develop alternatives to meet those needs. Hydro One then analyzes the alternatives and proposes a candidate investment.[5] All of the need, alternative and alternative selection information is entered into the Asset Investment Planning tool where it undergoes various managerial reviews.

Hydro One aggregates the pool of candidate investments into a consolidated investment portfolio which undergoes a risk optimization. Then feedback from internal stakeholders and customers is considered to further optimize the investment portfolio. Once approved by Hydro One's Board of Directors, it becomes Hydro One's investment plan. Table 1 below shows how these reviews changed the size of the capital envelope for the test years.

[2] Exhibit B1-3-1, p. 1, Table 1
[3] Exhibit B1-2-7, p. 1 Figure 1
[4] Exhibit B1-2-1, p. 2, lines 3-13
[5] Exhibit B1-2-7, p. 14, lines 7-12, and Exhibit K4.4

Table 1
Transmission Capital Expenditures, 2017 – 2018
$ million

Investment Category	Candidate Investments		Optimization		Internal Stakeholder Engagement		Executive Approval	
Timeline	February 25 - March 3, 2017		March 11-14, 2017		March 17 - April 14, 2017		April 19, 2017	
	2017	2018	2017	2018	2017	2018	2017	2018
Sustaining	$ 934	$ 1,003	$ 748	$ 847	$ 777	$ 842	$ 777	$ 842
Development	$ 187	$ 186	$ 177	$ 164	$ 196	$ 170	$ 196	$ 170
Operations	$ 28	$ 37	$ 25	$ 31	$ 25	$ 31	$ 25	$ 31
Common Corporate Costs	$ 73	$ 80	$ 73	$ 84	$ 74	$ 74	$ 74	$ 74
Other	$ 4	$ 5	$ 4	$ 5	$ 4	$ 5	$ 4	$ 5
Total	$ 1,226	$ 1,311	$ 1,027	$ 1,131	$ 1,076	$ 1,122	$ 1,076	$ 1,122

Source: Exhibit J2.7, Table 1

Hydro One's proposed capital expenditures have increased significantly over historical expenditures and are forecast to continue increasing, as shown in Table 2.

Table 2
Transmission Capital Expenditures, 2012 – 2021
$ million

Investment Category	4 year Historical Actual Expenditures				Bridge Year	Test Year 1	Test Year 2	Forecast Expenditures		
	2012	2013	2014	2015	2016	2017	2018	2019	2021	2022
Sustaining	$ 389.3	$ 480.0	$ 621.3	$ 694.3	$ 724.3	$ 776.8	$ 842.1	$ 825.7	$ 915.2	$ 1,118.1
Development	$ 329.4	$ 171.7	$ 131.6	$ 166.0	$ 166.0	$ 196.4	$ 170.2	$ 244.0	$ 254.0	$ 258.3
Operations	$ 15.2	$ 17.7	$ 28.4	$ 15.6	$ 30.1	$ 25.4	$ 30.8	$ 58.8	$ 21.1	$ 24.7
Common Corporate Costs	$ 42.1	$ 49.1	$ 63.4	$ 67.1	$ 83.5	$ 77.6	$ 79.1	$ 79.1	$ 78.2	$ 73.8
Total	$ 776.0	$ 718.5	$ 844.7	$ 943.0	$1,003.9	$1,076.2	$1,122.2	$1,207.6	$1,268.5	$ 1,474.9

Source: Exhibit B1/Tab3/Schedule 1/p.1

Development capital expenditure increases in the test years are due to major inter-area network projects, such as the Supply to Essex County Transmission Reinforcement and the capacity increase at Lisgar TS.[6]

Operations capital expenditure has increased significantly due primarily to the need for a new backup control centre and also the replacement of end-of-life replacement of grid control.[7]

Common corporate capital expenditure has increased over historical expenditures due to information technology development projects, increased facility needs for its sustainment, development and operations programs, and the purchase of a new helicopter.[8]

The Sustaining category of investments is both the largest contributor to the capital budget and the category that shows the largest increase over historical (2012 – 2016) spending levels. OEB staff will focus the first part of this section of its submission on the proposed sustaining investments.

OEB staff accepts that Hydro One must undertake capital projects in the test years to maintain its system integrity, and public and worker safety. However, staff submits that

[6] Exhibit B1-3-1, pp. 4-5
[7] Exhibit B1-3-1, p. 5
[8] Exhibit B1-3-1, p. 5

the OEB should not approve Hydro One's entire proposed capital budget for three main reasons:

- The capital spending on sustainment projects has not been fully justified
- The TSP and the evidence filed to support it was insufficient to demonstrate value to customers
- The customer engagement activity undertaken by Hydro One related to this application was inadequate.

Sustainment Spending

Lines

The pre-filed evidence[9] shows that the largest increase in sustainment spending over the bridge year is in the lines category. OEB staff accepts that much of the proposed spending for the test years in this category is necessary. The evidence of Mr. Ng during the oral hearing was persuasive that the proposed work on conductors is needed. In addition to the known age of the lines, and the recent observation that line-related asset failure is increasing, Hydro One has tested selected conductors. The lab testing shows that some conductors cannot be relied upon to resist failure under design loads. [10]

Similarly, Hydro One's proposal to replace faulty insulators was supported by an assessment of the condition of the assets. The assessment showed advanced deterioration, which increases the probability of failure. [11] While OEB staff will comment further on the apparent faults in the planning of the insulator replacement program, staff does not dispute that the work is necessary in the test years.

What OEB staff does question is the need for the level of spending proposed in the test years for tower recoating. The evidence shows that the deterioration in the towers does not pose any short or medium-term threat to reliability.[12] The expenditure is proposed in order to take advantage of what Hydro One describes as an economic opportunity, resulting from the identification of a new, more effective and efficient, tower coating product.[13] Hydro One's evidence, based on the net present value calculation filed, is that a delay in the tower coating will mean that the optimum time for recoating will be missed, and tower replacement will be necessary in the future.[14]

[9] Exhibit B1-3-1, Attachment 1, p. 1
[10] TR 5, p. 14, p. 101, p. 113, p. 171
[11] TR 5, p. 15, p. 162, p. 167
[12] TR 6, p. 123
[13] TR TC 2, pp. 71-72, TR 5, p. 12, p. 15, pp. 173 - 174
[14] TR 5, p. 15, pp. 173 - 174

While staff appreciates Hydro One's effort to identify opportunities to optimize spending, it is also true that electricity customers in Ontario are very concerned about rising electricity bills. Mr. Ng identified the tower work as the least important of the three lines initiatives,[15] and the net benefit of the timing is reduced if Hydro One's assumptions about future economics factored into the discount rate (e.g. the weighted average cost of capital) are not accurate.[16] Staff recommends that the OEB, when considering the capital expenditure envelope, find that the tower coating work can be reduced in the test years with no near-term risk to reliability or significant loss of economic benefit.

Stations

Staff submits that the proposed expenditure on stations has not been fully justified. The increase in capital spending over the bridge year is largely due to lines work, but the majority of the proposed sustainment capital spending is directed at stations projects: $537 million in 2017 (lines $239.3 million) and $496.2 million in 2018 (lines $345.9 million).[17] As equipment failure at stations accounts for a small portion of outages suffered by customers[18], staff questions the emphasis on stations work in the test years. Staff also notes that spending on stations rose very significantly in 2014 and 2015.[19] The proposed budget for stations for 2017 is approximately 65% higher than in 2012.

Hydro One has argued that the deferral of stations work will increase the likelihood of asset failure, causing consequences to customers and execution challenges from having to undertake repairs or replacement of failed assets.[20] Asset failure becomes more likely as station assets age. However, Mr. Ng agreed that failure can occur for any transformer, and failure for this type of station asset is not necessarily related to age.[21]

Hydro One's evidence also suggested that deferral of stations work would cause challenges during the period 2022 to 2030, as nuclear refurbishment is planned for that time period.[22] It would be important, it was argued, to co-ordinate outages with nuclear generation operators, and ensure that the transmission system is ready to accept generation from a variety of sources.[23] However, staff notes that while Hydro One has spoken to Bruce Power and Ontario Power Generation about their plans, the company

[15] TR 5, p. 180
[16] Exhibit J5.4
[17] Exhibit B1-3-1 Attachment 1, p.1
[18] TR 1, p. 135, 1, p. 169, Exhibit B1-2-2, Attachment 2, p. 13, and Exhibit B1-2-4, p. 8, Table 1
[19] Exhibit B1-3-1 Attachment 1, p. 1, Exhibit B1-3-2 page 10, table 2
[20] TR 2, p. 9
[21] TR 6, p. 39
[22] TR 2, p. 15, TR 5, p. 158
[23] TR 5, p. 161, TR 7, p. 50

still needs to have a detailed discussion with the Independent Electricity System Operator before it knows the actual limitations it will face during that period.[24]

Further, an examination of the investment summary documents for stations sustainment projects reveals that approximately $220 million of the station sustainment capital spending for each test year is related to load serving stations: [25]

Table 3
Stations Sustaining Capital Expenditures, by station purpose
2017 – 2018, $ million

	2017	2018	Total
Generation	$ 96.6	$ 103.6	$ 200.4
Load	$ 222.5	$ 218.7	$ 441.2
Both	$ 120.7	$ 53.1	$ 179.8
Total	$ 439.8	$ 375.4	$ 821.4

Source: Exhibit B1/Tab3/Schedule11, see Note below.

This suggests, in staff's view, that nearly half the proposed station work could be deferred without any concerns for coordination with nuclear refurbishments.

Hydro One's evidence also includes 10 station investment projects, which include functional reconfigurations of stations in addition to like-for-like replacements of assets.[26] These projects involve about $220 million of capital investment in the test years.[27] The station reconfigurations were driven by customer and system needs, such

[24] TR 5, p. 156, TR 5, p. 160
[25] The categorization was done by reviewing the need and station description in the ISDs for sustainment station projects (Exhibit B1-3-11, Reference # S01 to S50) to assess whether the station serves load, generation, both, or is a "network" station. Stations described as serving only load were categorized as load projects. Stations serving only generation were categorized as generation projects. Stations serving both and network stations were deemed generation and load: "both" projects. The costs for each station in the test years were taken from Exhibit B1-3-11 p. 1-2. Project capital investments outside the test years are therefore excluded. The costs were then added together for each category.
[26] Exhibit B1-3-2, p. 13-14
[27] Exhibit B1-3-2, p. 13-14

as reduced load and concerns over loading on the 115 kV network in Hamilton, respectively.[28] Some of the specific projects did not involve the IESO or the regional planning process.[29] The evidence is unclear whether the station reconfigurations have been designed with consideration for future needs in these regions.

Hydro One has claimed that the integrated approach to station sustainment work benefits customers by minimizing outages and reducing costs.[30] Staff agrees that outage optimization is beneficial, but submits that cost savings attributable to the integrated stations approach have not been proven.

Hydro One referred to several pieces of evidence in argument to demonstrate cost savings from consolidation of stations work. [31] However, while there may be cost savings on a per unit basis, it is not clear that overall savings are achieved. For example, the savings calculations assume that assets are retired or reconfigured only under an integrated stations approach. The assets could have been retired (if they were no longer needed) under the previous approach of asset-based stations work. The evidence does not clearly show that savings are truly achieved through the integrated stations approach. In the absence of this clear evidence the significant rise in stations expenditure (as this approach was being phased in) could seems to indicate that work is being undertaken unnecessarily.

<u>Reliability</u>

The OEB may wish to consider the company's proposals for sustainment expenditures in the context of Hydro One’s generally good record of reliability. Hydro One ranks in the top quartile among its Canadian Electricity Association (CEA) peers for reliability on its multi-circuit system.[32] The company's reliability to cost efficiency ratio is good.[33] Hydro One has pointed out that reliability statistics are a lagging indicator for the condition of the system, and that system redundancy in southern Ontario has prevented customer outages.[34] Hydro One asserted that its assets are ageing and deteriorating, even if this deterioration has not yet affected reliability.[35]

While staff accepts that Hydro One's system is aging, the actual reliability achieved through historical levels of spending suggests that the significant ramp-up in sustainment spending is unnecessary and can be better paced. Staff is not

[28] Exhibit B1-3-11, Ref #S08 to S17
[29] TR 6, p. 27, p. 34
[30] TR 6, p. 4, TR 6, p. 101, TR 6, pp. 127 - 128
[31] Hydro One Argument-in-Chief, pp. 49 – 50 (intended references in the Argument may be Ex. B1-3-2 p. 7 and Exhibit I-1-64)
[32] TR 1, p. 65
[33] TR 5, p. 154
[34] TR 1, pp. 96 – 72, TR 5, pp. 111 - 112
[35] TR 1, p. 71, p. 171, TR 6, p. 91

recommending that no increase in sustainment spending be approved by the OEB, but does submit that some reduction is warranted. As noted above, OEB staff submits that some station work could be deferred to ease the cost impacts to customers.

Staff accepts the evidence that reliability in northern Ontario, and particularly to some First Nation customers, is a real concern. [36] Where outages in the south may affect more customers, the impact of unreliability on customers in the north is very significant as demonstrated in the evidence presented by Anwaatin Inc.[37] Staff recommends that Hydro One keep this reliability differential, and its impact in mind as it undertakes the sustainment capital work in the test years.

Planning Evidence

A good understanding of the system plan underlying a proposed utility revenue requirement is essential for the OEB to set just and reasonable rates. The OEB has to be confident that the system plan is robust and provides value to customers. This understanding and confidence can be obtained only through cogent and comprehensive evidence of the system plan.

Staff submits that Hydro One’s TSP evidence was unclear and incomplete. Neither the pre-filed evidence, nor the interrogatories, gave a coherent and persuasive picture of the planning process and the needs underlying the plan. In staff's view, it was only during the oral hearing that the basis for the proposed capital investments became clear.

Inadequate Planning

There was some evidence that Hydro One's actual planning (as opposed to the planning evidence) was inadequate. The increase in proposed capital spending from that originally forecast for the test years in the previous application, [38] and the historic variance between proposed and actual capital spending, particularly in the sustaining capital area,[39] may indicate some fault in the planning process at the company. Some of the problems noted in the Planning Investment internal audit report had not been addressed prior to this application being filed.[40]

Hydro One argues that the proposed intensive work in the test years to replace Canadian Ohio Brass and Canadian Porcelain insulators is due in part to deferral of the

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[36] TR 7, p. 162
[37] Exhibits K13.2 and K13.3
[38] TR 1, p. 56
[39] Exhibit I-3-46, Exhibit TC J1.32, TR 1, p. 76
[40] Exhibit K4.4, TR 6, pp. 146 – 149, TR 7, pp. 136 – 137

work to defer cost impacts to ratepayers.[41] Staff submits that the present crisis with these insulators is not the result of an identification of the work needed and a deliberate choice to defer work to reduce cost impacts. Rather, the evidence suggests that Hydro One did not adequately monitor the insulators and plan its strategy for dealing with a large number of affected assets. In addition, it is not clear whether Hydro One sought compensation from the insulator manufacturers for the defects when those companies were still in existence.[42]

Staff submits that proper pacing of capital investments does not mean ignoring or minimizing an identified need, but spreading needed investments over a period of time that optimizes the balance between addressing the system need and avoiding sudden cost or rate impacts. Staff questions whether ratepayers should bear the entire cost of the intensive insulator replacement program. The potential fault with the insulators was identified in the 1980s, and failures occurred from 2004 to 2016,[43] but no specific replacement plan was produced until a public safety and reliability crisis arose.

<u>Inadequate Evidence</u>

Hydro One stated in its argument-in-chief that planning for the transmission system is very complex, and the company's planners are very experienced.[44] OEB staff agrees with these statements. However, staff submits that even if Hydro One's planning was ideal, the evidence in this application did not present a clear, coherent and comprehensive picture of the planning process or the reasons behind project selection. Hydro One's TSP was described as the culmination of several investment planning process streams,[45] but it was unclear how those process streams led to the proposals in this application.

In its pre-filed evidence and interrogatories, Hydro One presented several reasons for the proposed increase in capital spending, particularly sustainment spending.[46] In the course of the oral hearing, parties and the OEB panel learned that only one of these reasons had a major influence on proposed capital spending: new information about asset condition.[47] As indicated earlier, staff found the oral evidence persuasive as to the need for much of the lines work, but staff submits that the asset condition evidence should have been highlighted in the TSP and other written evidence as the main, if not the sole, reason for the proposed lines projects.

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41 Hydro One Argument-in-Chief, p. 39
42 TR 8, p. 19
43 Exhibit J 5.3
44 Hydro One Argument-in-Chief, p.13
45 Exhibit B1-2-1, p. 1, Figure 1, Exhibit B1-2-5, p. 1-5, Exhibit B1-2-7, p. 1, Figure 1
46 Exhibit B1-1-1, p. 1-2, Exhibit I-1-106, Exhibit J 2.7
47 TR 5, p. 100, TR 7, pp. 56 - 58

Hydro One creates Investment Summary Documents (ISDs) to support the proposals in its revenue requirement applications.[48] However, the comparison between the ISDs and the business cases developed for internal use for the same projects reveals significant inconsistencies and gaps. The ISDs are nearly all identical, list several needs, and include similar alternatives. The internal business cases filed by Hydro One do not mention some of the needs described in the corresponding ISDs, do not include alternatives described in the ISDs, and include significant safety concerns that are not described in the ISDs.[49] Although asset condition is the main driver behind the selection of projects,[50] the asset analytics scores, which give a quantitative measure of asset condition, are not included in the ISDs.[51]

The Auditor General criticized Hydro One's process around transmission line preventative maintenance. In defending the process, the witnesses stated that Hydro One always had a well-defined asset management strategy, but it was not formally documented.[52] Mr. Ng indicated that the action required was to consolidate and streamline the different pieces of documents into a single strategy document.[53] Staff submits that a similar issue may exist with the preparation of Hydro One's planning evidence for its revenue requirement applications: a reasonable process for identifying system needs and selecting projects exists, but that process is not adequately described in the TSP and supporting documentation.

OEB staff submits that the robustness of Hydro One's planning and the execution of its capital plan would be demonstrated by a report included in revenue requirement applications outlining the status of major[54] projects or programmes that appeared in the previous application. If a project or programme was not completed, or if money was redirected to a different project, the report should provide the reasons for the change. Staff recognizes that circumstances change and Hydro One may have to adjust its plans to meet unexpected difficulties or opportunities. A report on the status of the projects on which the revenue requirement envelope was based would assist the OEB, stakeholders and customers to understand how and why the approved capital expenditures were used.

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[48] TR 6, p. 8
[49] TR 6, p. 35, p. 38
[50] TR 6, p. 15, p. 77
[51] TC TR 2, pp. 63 - 64
[52] TR 6, p. 157
[53] TR 6, p. 157
[54] Projects exceeding $3.0 million in the test years.

Customer Engagement

Hydro One Transmission has ongoing interaction with its customers.[55] The company undertook more structured customer engagement before this application was filed. In general, customers who participated appreciated the opportunity to get an overall picture of the system and proposed investments, and Hydro One will continue this type of engagement.[56]

Timing of the Engagement

Although Hydro One's customers appreciated the effort made by the company, OEB staff submits that the customer engagement event took place too close to the filing date of the application to allow any real change to be made if it was warranted by the results of the engagement exercise.[57] Indeed, very little change was made to the TSP as a result of customer engagement.[58]

Selection of Participants

The entities invited to participate in Hydro One's focused customer engagement process were directly connected transmission customers and registered intervenors from the last two rate applications.[59] Given the requirements in Chapter 2 of the OEB's Filing Requirements for Electricity Transmission Applications, staff submits that this approach was reasonable. However, OEB staff recommends that Hydro One, in its ongoing efforts at customer engagement, remind LDC participants that they are the source for the transmitter's knowledge of small end-use customers' views and preferences. Hydro One could have asked the LDC participants to specifically present the results of their own customer engagement exercises to inform the transmitter of the concerns of these customers.

The quality of electricity service to First Nations, and the needs of those customers, has come under increasing scrutiny in this hearing with the participation of, and evidence presented by, the Anwaatin First Nations. Staff encourages Hydro One to obtain information about the needs of these customers through the participation of Hydro One Distribution, Hydro One Remotes, other distributors that serve First Nations, and the Anwaatin First Nations and other First Nations organizations, in Hydro One Transmission's ongoing customer engagement exercise.

[55] TR 2, p. 17, TR 4, p. 101
[56] TR 4, pp. 167 - 170
[57] Exhibit J2.7, Table1
[58] TR 5, p. 149, TR 5, p. 153
[59] Hydro One Argument-in-Chief, pp. 33-34

Lack of Focus on Costs

The main conclusion drawn by Hydro One from the engagement sessions was that reliability was important to customers, and that they were willing to accept increased capital spending to ensure no diminution of reliability.[60] This conclusion supported a slight increase in the proposed capital expenditures,[61] and Hydro One argues that the resulting revenue requirement increases are "consistent with the expressed customer preferences and tolerances regarding reliability risk".[62]

It appears that the material presented to customers assumed that customers would tolerate some cost increases above historic levels. The lowest cost scenario presented to customers proposed a spending increase 1.6% higher than historic spending increases, and Hydro One indicated this spending level would result in a 10% increase in "reliability risk".[63] Customers who enquired about a "zero" scenario that presumed a cost increase consistent with historic cost increases were told that “reliability risk” would increase by 20% under such a scenario.[64] A true "zero" scenario which involved no cost increase was not entertained by Hydro One, as the company believed the consequent deterioration of reliability was not acceptable.[65] Staff submits that the customer engagement exercise emphasised potential threats to reliability at the expense of a discussion probing customers’ views on and tolerance of cost increases.

Reliability Risk Model

OEB staff's main criticism of Hydro One's customer engagement process is that the choices presented to customers were based on a model for "reliability risk" that was not predictive of real-world reliability, was not used by Hydro One in planning its investments, and exaggerated the benefit of capital investments.

Hydro One's Reliability Risk Model was developed for two purposes: to provide a method for demonstrating the value of sustaining investments to customers, and to provide a directional indicator to assess the effect on reliability of an investment portfolio.[66] Staff sees the value in quantifying the benefits of capital spending in a way that will resonate with customers. However, staff submits that the Reliability Risk Model does not achieve this goal.

[60] Exhibit B1-2-2, p. 9, Exhibit B1-2-2, Attachment 1, p. 13
[61] Exhibit J2.7, Table 1
[62] Hydro One Argument-in-Chief, p. 33, TR 5, p. 105
[63] Exhibit B1-2-2, Attachment 2, p. 23
[64] Exhibit B1-2-2, Attachment 1, p. 26
[65] Exhibit B1-2-2, Attachment 1, p. 26, TR 7, p. 42
[66] TR 5, p. 133

Relationship to Actual Reliability and Planning

Hydro One believes that the Reliability Risk Model confirms a contribution to "reliability risk" that each asset type makes[67] and links assets beyond their expected service life to the impact on “reliability risk".[68] Hydro One agrees that the concept of "reliability risk" as calculated by the model is not predictive of real world reliability measures (SAIDI, SAIFI, CAIDI) in the short-term, but expects that over the long-term, unreliability due to equipment performance will be consistent with the results of the model.[69] As a communication tool, Hydro One uses the model results to show customers the expected reliability outcomes of various levels of sustaining investment.[70]

Unfortunately, the actual reliability experienced by customers is partially driven by factors outside the transmitter’s control, such as weather.[71] A relationship has not been established between the results of the Reliability Risk Model and actual reliability.[72] The criticality of assets, which is very important in determining risk and planning investment priorities, is not taken into account in the model.[73]

Hydro One agreed that it does not use the Reliability Risk Model in its planning, and the portfolio of proposed projects would be the same with or without the model.[74] Although Hydro One testified that customers said they understood the difference between real world reliability and the results of the model,[75] staff questions the value of feedback obtained from customers using a model that Hydro One itself admits is irrelevant to the construction of its investment portfolio.

Testing the model

OEB staff understands that reliability statistics are a lagging indicator of system integrity and that the risk of unreliability can increase without immediately affecting actual reliability. The model attempts to provide a leading indicator of system health. However, the value of the model as a communication tool would be proven by a demonstration that the results from the model are correlated with real-world reliability.

Hydro One argues that the model at present cannot be tested to confirm the belief that as calculated "reliability risk" declines for an asset type, there should be a lower

[67] TR 1, p. 134
[68] TR 2, p. 133
[69] TR 5, p. 122
[70] TR 5, p. 123
[71] TR 1, p. 136, Exhibit B2-2-1 Attachment 1, p. 22, Figure 19
[72] TR 5, p. 128
[73] TR 5, p. 134
[74] TR 1, p. 127
[75] TR 5, p. 134

contribution to real-world reliability from that asset type.[76] Dr. Elsayed explored with the witness whether historical data, normalized to exclude extreme events, could be used to explore whether the results of the model correlate to actual reliability in the past.[77] The company argues that back-testing the model is not practical, and testing must wait for data from future baseline levels.[78]

OEB staff does not understand why back-testing cannot be done. For example, a calculation of "reliability risk" could be made on the basis of assets in place five or ten years ago and another calculation could be made based on assets in place in 2016 (or the latest year with complete asset data). Then actual reliability for the interval could be compared to the change in "reliability risk" predicted by the model in the earlier year. If Hydro One does not think such an approach would work, it should identify how many years of future data will be needed before the results of the model can be validated.

Exaggeration of benefits

Based on its understanding of the model, staff believes that the simplifying assumptions made in the model mean that the results exaggerate the benefit of capital spending on assets. The model uses hazard curves that presume that an asset has a near-zero risk of failure for most of its life, and that risk trends rapidly upward as the asset reaches presumed end of life.[79] The hazard curves are based on age, not condition.[80] At the same time, the model assumes that the oldest asset in a group is replaced first.[81] In combination with the shape of the hazard curves, this assumption about the order of replacement maximizes the risk reduction achieved by the asset replacement.

Mr. Penstone testified that just because equipment is at the end of its expected life, it does not mean that it is about to fail.[82] Hydro One bases its actual replacement decisions on the condition of the assets.[83] As a result, the theoretical "risk" calculated by the model is not the same as actual system risk.[84] In addition, the model assumes "failure" of an asset if the asset is retired for any reason, including, for example, as part of an integrated station project.[85] This assumption shortens expected service lives and increases the failure rate in hazard curves, further exaggerating "reliability risk" and the benefit of capital investments. While Hydro One did tell customers that "reliability risk"

[76] Hydro One Argument-in-Chief, p. 31
[77] TR 4, pp. 178 - 180
[78] Hydro One Argument-in-Chief, p. 31
[79] TR 5, p.137
[80] TR 1, p. 66, TR 5, p.145
[81] Exhibit I-1-21(b), Exhibit I-1-22(f)
[82] TR 5, p. 128
[83] TR. TC 2, p. 49, TR 5, p. 171
[84] TR 5, p. 146
[85] TR TC 2, p. 52

and real-world reliability are not the same, it is not clear whether customers knew that the Reliability Risk Model maximizes the potential benefits of capital spending.

Proposed Reduction to Capital Budget

Staff submits that the OEB should not approve in full the proposed capital expenditures for the test years. Staff submits that an amount of $113.8 million should be deducted in each of 2017 and 2018. Those figures are equivalent to 50% of the increase proposed in the sustainment budget for the test years over the average sustaining capital expenditure for the period 2012 – 2016. In addition, staff submits that the OEB should consider a further disallowance to signal to the company that the quality of its planning evidence and customer engagement activity was below the standard the OEB expects from a large, sophisticated utility. Staff suggests that this disallowance should be an amount of $22.76 million in each test year (20% of the proposed sustainment budget disallowance), for a total reduction of $136.56 million. Staff proposes that the OEB reduce the capital envelope rather than attempt to apply a reduction to specific projects or programs, as Hydro One may need to adjust the execution of its plan during the test years.

The reasons for staff's proposed reduction have been explained in detail above, but in summary are:

- Hydro One's statement that all proposed sustainment work must be completed in the test years was not supported by the evidence. While the conductor and insulator work is urgent, the tower recoating and stations work could be paced to reduce cost impacts, in staff's submission.

- The TSP and the evidence filed to support Hydro One's capital expenditures did not demonstrate that the planning behind Hydro One's TSP was robust. There were areas of confusion, and inconsistencies between the evidence provided to the OEB and the process and materials actually used to plan investments. The planning evidence does not provide the OEB with the confidence necessary to find that the proposed investments provide real value to customers.

- The value of the formal customer engagement undertaken by Hydro One and the benefit of the consequent increase in proposed capital spending have not been demonstrated. The evidence suggests that the customer engagement exercise occurred too late to be given serious consideration in the TSP, and the engagement relied on a model that exaggerated the benefit of capital spending.

OEB staff recognizes that the demographics of Hydro One's assets pose challenges, and that the impact of the proposed revenue requirement on end-use customers' total bills is modest. However, careful prioritization and pacing of capital investments is a key aspect of utility planning.

Staff takes issue with the argument made by Hydro One that the choices facing the company are either to replace assets or rely on hope.[86] The choice is not so one-dimensional. Pacing is not equivalent to relying on hope. Hydro One itself has in the past chosen to delay work that it had identified as needed. Pacing is the result of good judgment applied to balance system needs with cost impacts on customers.

Reporting on Status of Projects

As stated earlier, OEB staff also submits that Hydro One should be required, in its revenue requirement applications going forward, to report on the status of major[87] projects or programmes that appeared in the previous application. If a project or programme was not completed, or if money was redirected to a different project, the report should provide the reasons for the change.

Line Losses

Environmental Defence (ED) submitted evidence regarding the loss minimization practices of utilities in other jurisdictions.[88] ED's evidence advocates for measuring and reporting losses, benchmarking transmission losses, considering transmission losses in operational and investment decisions, and encouraging reduction of losses through explicit incentives.[89]

Hydro One's direct examination addressed these points. Hydro One stated that many of the practices advocated by ED relate to the role of the IESO, which was grouped with the transmission owner and operators in some other jurisdictions.[90] Accordingly, Hydro One submitted that the IESO is better placed to measure and report on losses, benchmark transmission losses and encourage losses through explicit incentives.[91] Staff agrees that the IESO should have a role.

Hydro One also stated that the planning of the transmission system and incorporating losses into planning decisions lies with the IESO through its regional planning

[86] Hydro One Argument-in-Chief, p. 37
[87] Projects exceeding $3.0 million in the test years
[88] Exhibit K 12.4
[89] Exhibit K 12.4 p. 2
[90] TR 5, p. 28
[91] TR 5, p. 32

process.[92] Hydro One acknowledged that many planning decisions such as choice of conductor and station reconfigurations, as proposed in this application, are planning decisions largely made by Hydro One without any input from the IESO.[93]

ED questioned Hydro One about the cost of losses considered in Hydro One's asset design choices.[94] Staff accepts that there is merit in considering the full cost of losses, including energy costs as well as generation, transmission and distribution capacity costs. Hydro One demonstrated that its purchases of transformers include some consideration of losses but it was unclear whether it considers the full cost of losses.[95]

Hydro One stated that the extent of losses in Ontario is low and unlikely to change significantly due to new investments.[96] Further, the value of losses is generally too small to justify significant changes to existing assets.[97] Staff submits that Hydro One should ensure that it has fully considered the cost of losses when it makes asset design and purchase decisions.

Benchmarking

Hydro One provided a reliability and total cost benchmarking study in its TSP.[98] The benchmarking study presents two sets of reliability performance metrics: a set of asset outage information from the Transmission Availability Data System (TADS) and another based on CEA statistics.[99] Hydro One emphasized that under CEA reliability metrics, Hydro One has top quartile reliability performance for its multi-circuit system,[100] and has included maintaining top quartile reliability performance as a key outcome for its TSP.[101] However, the TADS metric shows that Hydro One has the worst or close to the worst reliability performance of all the utilities in the peer group.[102] This apparent contradiction is explained by two factors:

- The two reliability studies used different peer groups
- The CEA statistics considered only the southern, multi-circuit portion of Hydro One's transmission system, while the TADS metric considered the entire system.

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[92] TR 5, p. 66
[93] TR 5, p. 67
[94] TR 5, pp. 76 - 77
[95] Exhibit J5.1
[96] TR 5, p. 36
[97] TR 5, p. 39
[98] Exhibit B2-2-1
[99] Exhibit B2-2-1, Attachment 1, pp. 20-23
[100] Exhibit B1-1-3, p. 18, lines 15-18
[101] Exhibit B1-1-9, p. 1, line 13
[102] Exhibit B2-2-1, Attachment 1, p. 21-22

Reliability is much lower in the northern, radial portion of Hydro One's system.

The objective of benchmarking is to assess the performance of a utility relative to other utilities, and thereby assess the reasonableness of the spending proposals in the application. Benchmarking is a fundamental part of the OEB's approach to regulation under the RRF. To be truly useful, benchmarking studies must compare performance on both cost and benefit metrics to assess whether a utility is performing well relative to its peers. While the evidence filed by Hydro One does provide some useful information, staff submits that it has two main flaws.

First, it is difficult to assess cost performance against reliability performance because two reliability metrics were given, and each metric was based on comparisons to different peer groups. Hydro One used the CEA peer group data to show good reliability, while using the other peer group data to claim that the company has been underinvesting in sustainment relative to other utilities.[103] Mr. Grunfeld of Navigant agreed that it is difficult to make that comparison and that it would be preferred to use a consistent peer group.[104]

Secondly, the reliability performance metric used by Navigant and Top Quartile consulting is not particularly helpful in assessing the impact to consumers because it considers only asset outages, which may not actually cause a customer outage.[105] Further, Navigant and Top Quartile did not assess the system design differences among different utilities.[106] If a utility's system includes a lot of redundancy, as Hydro One's multi-circuit system does, then that utility could have more asset outages while maintaining similar customer interruptions to other utilities with fewer asset outages.

Staff agrees with Hydro One's submission that benchmarking must be considered in the context of the variations between utilities.[107] Staff submits that Hydro One should structure its future benchmarking studies to choose the best available peer group to compare both costs and reliability performance. In addition, while staff acknowledges that customer outages are partially driven by exogenous factors such as weather, some metric should be presented that measures reliability in terms of a customer's experience.

[103] Exhibit B1-2-2, Attachment 2, Slide 18
[104] TR 3, p. 124, lines 12-19
[105] Exhibit B2-2-1, Attachment 1, p. 20
[106] Exhibit B2-2-1, Attachment 1
[107] Exhibit B1-1-3, p. 1-2

Scorecard

Hydro One filed its proposed transmission scorecard and numerous key performance indicators (KPI) for its transmission business at Exhibit B2Tab1/Schedule 1. The Scorecard and related KPIs are aligned with the four outcome categories of the RRF: Customer Focus, Operational Effectiveness, Policy Responsiveness and Financial Performance.

The transmission scorecard also aligns with the metrics found on the annual distribution scorecard that is submitted to the OEB.[108] Hydro One developed its KPIs as additional Tier 2 and Tier 3 metrics in order to augment the metrics in the scorecard (which it also referred to as Tier 1 metrics).[109]

OEB staff agrees with Hydro One that, “The ability to measure performance, make year over year comparisons and benchmark against peers provides important information for measuring operational effectiveness and identifying areas for improvement”.[110] The KPIs are directly tied to non-union compensation plans.[111]

In general, OEB staff supports Hydro One’s efforts in this area, working to develop key performance indicators and metrics, aligned with the RRF and tied to the granting of performance based compensation for Hydro One management. Staff also supports the continued development of the Tier 2 and Tier 3 KPIs and submits that the OEB should require Hydro One to report on the further steps taken to strengthen these metrics in its next rates application. In addition, staff encourages Hydro One’s efforts to look at stretch targets for these metrics.[112]

However, staff is concerned that some of the scorecard and KPI metrics cannot be benchmarked. When asked about this issue in interrogatory I-11-11, Hydro One responded that “[w]hen developing the proposed scorecard, discrete data that provides viable comparisons to the measures listed was not readily available from other transmitters.” While staff recognizes that not all metrics should be benchmarked and there may be difficulties in determining external benchmarks for all KPIs, Hydro One is urged to continue its efforts to do so. In the meantime, the measures can provide information about Hydro One’s own success at continuous improvement.

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[108] Exhibit I-11-11
[109] Hydro One Argument-in-Chief, pp. 52-53
[110] Exhibit B2/Tab1/Schedule 1, p. 1
[111] Hydro One Argument-in-Chief, p. 54
[112] Exhibit I-1-92 b)

During the course of the hearing, OEB staff enquired about a cost per unit metric, either in $/MWh of energy delivered or $/MW-year of capacity billed to customers, as a measure of total costs to be borne by rate payers over the years. This was asked in order to address one of the paramount concerns (along with reliability) of customers which is the cost of receiving electricity service. Hydro One replied that normalizing cost (either OMA or capital) by energy delivered (MWh) or MW of capacity billed, has been considered in the past, but argued that costs based on unit volume do not account for differences in the geography, topography and customer density of a utility's service territory and its overall system size.[113] This issue was explored again by Energy Probe[114] and later by staff[115]. Hydro One continued its opposition to such a measure, emphasizing that the difference in size and territory characteristics would compromise benchmarking with other jurisdictions.

Staff suggests that trend analysis could be useful, i.e. that changes in costs can be tracked from year to year. Hydro One could both demonstrate its own progress, and compare its cost trends with the cost trends for other transmitters, rather than an absolute measure of costs.

Hydro One also took the position that costs per kWh or kW installed would not be a useful measure to track as many of the costs apply regardless of the amount of energy delivered or infrastructure in place. Staff is of the view that recording year over year costs per kWh might provide some indication of the trend in overall system efficiency, or at minimum provide a starting point for the OEB and stakeholders to better understand the relationship of costs to system usage. Staff accepts that Hydro One would need to supply information on factors other than system usage that drove costs in any particular year.

In summary, staff believes that a simple to understand metric of revenue requirement per kWh sold and/or kW installed would give customers, stakeholders and the OEB an appropriate general measure of Hydro One's transmission cost trends.

Staff also submits, in light of the evidence provided by Anwaatin, that Hydro One place additional emphasis on elevating the Tier 2 and 3 metrics concerning interruption frequency in the single circuit system, to their Tier 1 scorecard to directly reflect the different reliability records of these two systems.

[113] Exhibit I-1-91
[114] TR 1, pp. 143 -145
[115] TR 2, pp. 149 -151

Operations, Maintenance and Administration (including Compensation)

In the application, at Exhibit C1, Hydro One outlined its Operations, Maintenance and Administration (OM&A) expenses for several historic years, the bridge year and the two test years. These amounts, listed by main categories are shown in the table below.

Table 4
Operations, Maintenance and Administration Expenditures, by Major Category
2012 – 2018, $ million

	Actual 2012	Actual 2013	Actual 2014	Actual 2015	Bridge 2016	Test 2017	Test 2018
Sustainment	$ 204.7	$ 221.0	$ 228.6	$ 233.6	$ 227.5	$ 241.2	$ 238.5
year to year percentage change	-	8.0%	3.4%	2.2%	-2.6%	6.0%	-1.1%
Development	$ 8.4	$ 8.6	$ 7.5	$ 6.1	$ 5.3	$ 4.8	$ 5.0
year to year percentage change	-	2.4%	-12.8%	-18.7%	-13.1%	-9.4%	4.2%
Operations	$ 54.8	$ 56.7	$ 56.6	$ 59.0	$ 60.0	$ 61.3	$ 62.1
year to year percentage change	-	3.5%	-0.2%	4.2%	1.7%	2.2%	1.3%
Customer Care	$ 4.4	$ 5.3	$ 5.4	$ 5.1	$ 4.1	$ 4.0	$ 3.9
year to year percentage change	-	20.5%	1.9%	-5.6%	-19.6%	-2.4%	-2.5%
Common Corporate Costs & Other	$ 80.7	$ 75.8	$ 37.2	$ 73.9	$ 72.3	$ 49.9	$ 47.5
year to year percentage change	-	-6.1%	-50.9%	98.7%	-2.2%	-31.0%	-4.8%
Taxes other than Income Taxes	$ 62.1	$ 21.2	$ 64.1	$ 63.9	$ 62.9	$ 63.6	$ 64.3
year to year percentage change	-	-65.9%	202.4%	-0.3%	-1.6%	1.1%	1.1%
Pension & B2M LP Adjustments						-11.8	-10.1
Total OM&A	$ 415.1	$ 388.6	$ 399.4	$ 441.6	$ 432.1	$ 413.0	$ 411.2
year to year percentage change	-	-6.4%	2.8%	10.6%	-2.2%	-4.4%	-0.4%

Source: Exhibit C1/Tab2/Schedule1/Table 1

Staff notes that this table shows a slightly decreasing OM&A cost in the bridge and two test years compared to previous years. However, the table also shows that the major impact on the decrease in overall costs is the Common Corporate Costs and Other category, which benefits from a significant increase in capitalized OM&A.

In addition, the 2017 and 2018 adjustments are primarily driven by a reduction in pension costs, which could be viewed as an exogenous variable that reflects a decision to push forward the reporting of these pension amounts. The reduction is not due to any pension cost saving action by Hydro One.

Staff will address the overall OM&A costs with a focus on four specific areas:

a) The expected reduction in OM&A spending as capital investment increases and old and aged equipment requiring operations and maintenance spending is replaced by new equipment.

b) The seemingly consistent under-spending of the OM&A budget approved by the OEB in the historic years leading up to the two test years, and a pattern of over-estimation of OM&A spending which results in higher rates than are warranted.

c) The rising corporate management costs which contribute to a higher revenue requirement. Higher costs in this category could arguably be the result of the corporate restructuring (the IPO), which do not contribute to the enhancement of services to transmission customers and therefore should not be funded by ratepayers.

d) The rise in compensation costs and the impact of increasing compensation for the CEO and CFO and other senior management (the subject of the Hugessen and Towers Watson evidence[116]) and the rise in overall compensation which is documented in the Mercer Compensation Cost Benchmarking Study Report[117] (the Mercer Report) filed in the case.

All of these factors compel OEB staff to argue for a reduction in the overall OM&A costs proposed in the application.

Expected Decline in OM&A costs as Capital Spending Increases

As shown in Table 1, Hydro One’s sustainment costs rise steadily over the 2012 to 2017 time frame except the bridge year where a 2.6% decrease is shown. Staff notes that sustainment capital spending increases significantly in the test years. As new assets replace older deteriorated assets at or near end of life, staff submits that it is a reasonable expectation that sustainment OM&A spending would be reduced to reflect that new assets require less operations and maintenance spending than older assets. This factor seems not to have been reflected in the Sustainment Operations and Maintenance budgets for the test years. Although the evidence as filed did not allow for

[116] Exhibit I-6-057
[117] Exhibit K9.8

staff to specifically quantify how much sustainment OM&A spending should fall as a result of this capital investment, staff submits that a reduction in the OM&A cost is warranted for the test years. Staff submits that an approximate 5% reduction in Sustainment OM&A, an amount of $12 million is an appropriate reduction for each of the test years for this issue.

Consistent OM&A spending in Excess of Approved Levels

Hydro One's response to IR I-13-25 shows how actual OM&A spending performance compares to the approved OM&A level each year from 2012 to the 2016 bridge year. In every year but 2015, Hydro One has spent less than the amount recovered in rates. For 2012 the over-recovery is $12.1 million, for 2013, $11.6 million (adjusted by the unforeseen tax refund), for 2014, $50.3 million, for 2015 there is an overspend of $10.4 million and in 2016 an underspend of $4.7 million. This is an underspend total of $68.3 million over 5 years, an amount that ratepayers have funded through rates but was not actually needed by Hydro One. The average under-spending is $13.6 million per year.

Staff also notes that in IR I-2-30 Hydro One provides its historical Rate of Return on Equity from 2012 to 2015 showing that earnings exceeded the deemed amount embedded in its revenue requirement by 2.99%, 4.29%, 3.76% and 1.63% respectively. In addition, for the partially completed 2016 bridge year, the current estimate is 2.5%.[118] While other factors are also in play, staff suggests that a significant portion of the excessive ROE is the under-spending of OM&A over that period.

Staff submits that the consistent historical under spending of OM&A by Hydro One should result in an additional adjustment to OM&A totals for each of the two test years in the range of $15 million.

Corporate Management Cost Increases

Hydro One's evidence at C1/Tab3/Sch1 and at IR I-4-12 (Table 1) with supplementary information provided at IR I-1-121, shows that corporate management costs are rising rapidly, despite the fact that $6.3 million of these costs were already removed from the transmission business allocation.[119] The evidence referenced above shows that Corporate Management costs allocated to transmission averaged $2.5 million from 2012 to 2015, before jumping up to $4.0 million in 2016 and then to $7.2 million in 2017 and $7.1 million in 2018. Similarly, in response to IR I-13-18, Hydro One shows the

[118] TR 1, p. 85
[119] TR 2, pp. 143-146

increasing Board of Director costs beginning in 2016 and increasing into 2017 and 2018.

When cross examined on this issue in the oral hearing, Mr. Vels defended these increases indicating that these increases are "…not a reflection of the fact that it's a public company. It's a reflection of the level of management that is required to run the company."[120]

Despite the testimony by Mr. Vels, these costs are growing significantly in the 2016 year and following years which are post IPO. It is apparent that the new post IPO management requires a higher level of management costs. Staff submits that these increases are excessive, have little to do with increasing value to transmission customers and therefore should not be borne by customers.

A similar phenomenon can be observed in the area of Corporate Communications and Services, where the average spending from 2012 to 2015 was $7.2 million per year and in 2016 grows significantly to $8.7 million, continuing into 2017 and then growing again in 2018 to $9.9 million.

Staff submits that disallowance of a portion of these costs is justified and suggests an approval amount slightly higher than the 2012 – 2015 averages for these two specific areas: $3.7 million for Corporate Management costs and $7.7 million for the Communications portion. This would mean a disallowance of $3.5 million in each test year for Corporate Management and $1 million in 2017 for Communications followed by $2.2 million in 2018.

Increasing Total Compensation costs

A significant portion of OM&A costs are due to the compensation provided to the employees of Hydro One. Hydro One provided an overall summary of its compensation costs in a summary table[121] which was also provided as an excel spreadsheet.

In the course of the oral hearing, OEB staff counsel Mr. Millar clarified exactly what was included in this data, that is, obtaining the definition of "Other Allowances", and determining that "Lump Sum" payments were included in Base Pay for Power Workers Union (PWU) and Society of Energy Professionals (Society) staff. Also determined was the fact that pension costs were not included, "Other Post Employment Benefit" costs

[120] TR 2, p.144
[121] Exhibit C1/Tab 4/Schedule 1/Attachment 1

(OPEBs) were not included and that the cost of share grants were also not included in the totals.[122]

Previously, Mr. Rubenstein, counsel to SEC, requested that the total compensation table referred to above be augmented to include all compensation costs. This was provided as Undertaking J10.2 where Hydro One also made a 'best efforts' attempt to split the compensation costs between the Transmission and Distribution businesses.

The additional information that was provided in the undertaking was the item identified as "Burdens" which contained the embedded Pension and OPEB costs, and the share grant costs. This then presented a complete picture of the total compensation costs for the transmission business, qualified by the assumptions provided with the response.

While this filing was helpful in providing total compensation costs for the transmission business, it was less helpful in that comparable employee counts were not provided. Without the employee counts the cost per employee and the change in that cost over time, is not obtainable. The filed information makes it difficult to determine the actual increases in total compensation over the test and historic years.

OEB staff submits that Hydro One should have provided a complete picture of compensation costs as shown in the compensation summary table by adding in pension costs, OPEBs costs and share grant costs. In addition, the company should refine its methodology for splitting compensation costs between its two regulated businesses, including the allocation of number of employees that generate those costs, in order to provide a comprehensive record of total compensation. It would be helpful to all parties if this could be provided for the next transmission application as well as the next Hydro One distribution application to be filed in early 2017.

OEB staff recognizes that Hydro One has made strides in reducing compensation levels with the increased use of casual labour, the slow but steady reduction of regular staff over the past few years and efforts to reduce overtime. Hydro One has also achieved some reductions in pension costs in its union agreements with slightly higher contribution levels from employees and the introduction of share grants (which works to align the interests of employees with the company interests). However, OEB staff is somewhat surprised that new employees are not eligible for share grants, which appears to be a step backwards for Hydro One.[123]

[122] TR 11, pp. 171 – 175
[123] TR 10, p. 12

As mentioned previously, Hydro One also filed compensation information in the form of the Mercer Report 2016 update. The Mercer compensation study has been a mainstay of Hydro One applications, having been filed as compensation benchmarking evidence for the years 2008, 2011, 2013 and now, 2016. The OEB has relied on these study results in past Hydro One rates decisions. It is important to note that this study considers all aspects of compensation including pensions and OPEBs.

The most recent study results (page 12 of the K9.8 slides) show that Hydro One's compensation is farther above the median than in 2013:

- Non-Represented staff went from 0.99 of the 50th percentile in 2013 to 1.02 of the 50th percentile in 2016.
- Professionals went from 1.09 of the 50th percentile in 2013 to 1.11 of the 50th percentile in 2016.
- Power Workers represented staff went from 1.12 of the 50th percentile in 2013 to 1.16 of the 50th percentile in 2016.

Overall, the 2016 study showed that Hydro One compensation had not continued its previous steady trajectory toward lower compensation levels (in comparison to the 50th percentile). In 2008, the overall score was 1.17, in 2011 it fell to 1.13, in 2013 it fell further to 1.10 but in 2016 increased to 1.14.

Staff submits that Hydro One's compensation performance as revealed in this study is disappointing as progress toward the P50 level over the past years has been reversed.

In Exhibit K9.8, Hydro One outlined various efforts it has made to reduce costs (increased pension contributions, lower base wages replaced by lump sum payments, etc.), but did not mention that share grants are now part of the compensation package for most employees (PWU and Society) which would offset some of these factors.

In addition, staff notes that the response to Undertaking J10.3 reveals that lump sum payments were not included in the data considered by Mercer, potentially making the results worse, albeit by a minor amount.

As part of this study, Hydro One requested that Mercer estimate the dollar difference between the weighted average total compensation for Hydro One employees and P50 median for the peers included in the study. Using the same methodology as used in the study, Mercer determined the difference to be $71 million of which 17.6% or $12.5 million is allocated to Transmission OM&A.

Staff submits that the OEB should reduce the OM&A envelope for recovery from ratepayers by the $12.5 million difference in both test years. Staff notes that the OEB made a similar disallowance based on the 2013 Mercer Study results, in the EB-2013-0416 distribution case. In that instance, the OEB reduced recovery by only half the amount cited by Mercer. Staff points out that in that hearing, the Mercer results showed a steady improvement by Hydro One in moving to the median. In the present case, that improvement has reversed somewhat, and that is the basis for the staff submission to remove the entire amount.

The other compensation studies filed (Hugessen and Towers/Watson) also revealed compensation in excess of the P50 level for Hydro One. The Hugessen report showed that compensation for the Hydro One CEO and CFO is at or above the P75 level. As mentioned many times in the hearing, it is Hydro One's practice to target the 50th percentile for compensation.[124] When referencing the Towers/Watson utility peer group, the cost difference between the P50 and P75 levels is in the range of an extra $500,000 for the CEO and $200,000 for the CFO.[125]

The Towers/Watson study also reviewed compensation for the 453 non-represented employees below the level of vice-president and revealed that this group was 10 percent above the 50th percentile. More specifically, the 250 support role employees were in the 75th percentile range.[126]

Technical Conference Undertaking TCJ1.6 showed that management pay bands in excess of the P50 level amounted to an additional $6.3 million in compensation costs.

Staff submits that a further reduction be made that takes into account the results of the Hugessen and Towers/Watson studies in the amount of $700,000 for the CEO and CFO excess of P50 levels and an additional $6.3 million for the other executives covered in the Towers/Watson study, in each of the test years.

OEB staff also notes that a significant portion of senior management total compensation is variable, that is, dependent on performance. Hydro One has included a Long Term Incentive Plan (LTIP) and a Short Term Incentive Plan (STIP) in these compensation packages to align with the market and to incentivize continuous improvement through "at risk" compensation. These variable aspects of total compensation are intended to be

[124] TR 9, p. 130
[125] TR 9, pp. 138-139
[126] TR 10, pp. 59-60

aligned with Hydro One's proposed Transmission Scorecard and the principles of the RRF. [127]

The Towers/Watson witness, Mr. Resch, described the LTIP as made up of performance share units and restrictive share units based on earnings per share targets and maintenance of the dividend rate. LTIP compensation for the Hydro One CEO is $2.4 million and for the CFO, $700,000.[128]

While OEB staff supports compensation that is driven by achievement of scorecard outcomes, staff questions the value to ratepayers of compensation tied to metrics such as earnings per share. While the goal of growing earnings per share may be appropriate for a private sector corporation, it does not seem appropriate that customers of a regulated transmission or distribution company pay for this. Transmission customers are most interested in low costs, high reliability and good customer service, not whether earnings per share or share price appreciate.

Even the Hugessen witness, Mr. Soare, indicated that he would have "…a bit of a challenge describing the relevance to the ratepayer" of this metric.[129]

OEB staff submits that Hydro One should reconsider the establishment of pay-for-performance metrics that are not aligned with ratepayer interests. If there are shareholder benefits that mean a CEO and CFO need to be paid a certain amount, the company can compensate accordingly, but staff submits that ratepayers should not pay for this. Accordingly, staff submits that the LTIP amounts should be removed from the revenue requirement. However, as these are long term payout amounts, staff is unclear of the amount of these costs that are embedded in the 2017 and 2018 revenue requirements, and invites Hydro One, in its reply argument to clarify this point.

Proposed Reductions

OEB staff has acknowledged that overall OM&A costs are dropping slightly over the bridge and test years. However, staff also points out that increasing capitalization of OM&A costs (as shown in the "other" category) can lead to a masking of actual operational increases.

Staff notes that OM&A costs, particularly in the Sustaining category do not show significant reductions, despite the increase in capital spending to renew assets. Staff

[127] Hydro One Argument-in-Chief, p. 58
[128] TR 9, p. 151
[129] TR 8, p.148, line 13.

submits that these costs should show a more pronounced reduction in the test years and suggests a reduction of 5% or $12 million in each test year would be appropriate for Sustaining OM&A.

Staff has documented the consistent OM&A under-spending by Hydro One and submits that this should result in a further reduction to OM&A totals for each of the two test years in the range of $15 million.

Staff has pointed out that certain Common Corporate costs appear to be rising disproportionately and that disallowances should be made for these high increases. These increases appear to have little to do with increasing value to transmission customers but more with the restructuring and IPO. Proposed reductions are $4.5 and $5.7 million for 2017 and 2018 respectively.

Staff also submits that a reduction of $12.5 million should be made for the deterioration in performance by Hydro One based on the results shown in the 2016 Mercer Study. Staff further submits that an additional reduction of $6.3 million be made for the executive level staff with compensation above the P50 level.

Staff has submitted that LTIP amounts for the CEO and CFO be removed from the revenue requirement but has asked Hydro One to clarify these amounts in their reply argument.

In total these proposed disallowances for OM&A are $54.1 million for 2017 and $55.3 million for 2018. (pending Hydro One’s reply on the LTIP issue). These reductions represent a 13% reduction in OM&A for each of the two test years.

Staff has two further recommendations: Improvements should be made in future applications to provide a more complete reporting of compensation costs for both Hydro One Networks in total and the separate Transmission and Distribution businesses. In addition, staff submits that if Hydro One expects to recover pay-for-performance costs should reconsider the establishment of pay-for-performance metrics that are not aligned with ratepayer interests.

First Nations Permits

During the course of the hearing, OEB staff raised questions regarding agreements or permits granted by the Department of Indian and Northern Affairs Canada (INAC). Hydro One has approval for its transmission (82 kilometres of transmission line) and distribution facilities to cross and/or occupy portions of First Nation reserves. Some of these permits and agreements require Hydro One to pay annual fees. The evidence shows that First Nations rights payments for the 2017 and 2018 test years are budgeted to be $1.5 million per year.[130]

In cross examination, Hydro One indicated that the permits were initially with Ontario Hydro but are now transferred to Hydro One. There is currently a process underway for negotiating new agreements with the First Nations. Until a new agreement is negotiated, Hydro One continues to pay First Nations for the assets on their reserves based on previous agreements that have expired.[131]

OEB staff submits that Hydro One should make genuine efforts to resolve these permit issues and ensure that First Nations rights are protected and appropriate compensation is provided.

Niagara Reinforcement Project

As part of its revenue requirement evidence, Hydro One indicates that it wishes to recover an amount characterized as "AFUDC recovery on Niagara Reinforcement Project". The amounts being sought for recovery are $4.6 million in each of the 2017 and 2018 test years.[132]

In the EB-2006-0501 transmission rates case, the OEB provided Hydro One with relief from the carrying charges that they would incur on the funds (debt) used to finance the Niagara Reinforcement Project (NRP). The NRP was not put into service as a result of a continuing land claim dispute in Caledonia, Ontario. At that time, the OEB did not put a limit on the period of time that Hydro One could recover the AFUDC on the NRP.[133]

Hydro One has now been recovering these costs in rates for 10 years, since January 1, 2007. It appears that Hydro One has not made any real progress in resolving this issue over that time period. OEB staff submits that the time has come for the OEB to disallow this cost beginning in the 2017 test year. This submission is made on the principle that regulated utilities are required to face some risk in their business operations, and that they are compensated for risk through their Return on Equity. Hydro One has been protected from the NRP completion risk for 10 years and there is no evidence that progress has been made in addressing this situation. A utility should have no expectation of a guaranteed recovery of costs for capital expenditures that have not

[130] Exhibit C1/Tab 3/Schedule 7/p. 4
[131] TR 8, pp. 174-176
[132] Exhibit E2/Tab1/Schedule 1
[133] EB-2006-0501 Decision With Reasons, August 16, 2007, p. 64

resulted in used or useful assets. OEB staff submits that there should be no further compensation unless the transmission line goes into service.

If the OEB decides some compensation will continue, OEB submits that this should no longer be through rate base at the weighted average cost of capital, but through a short-term interest rate.

Tax and Accounting Issues

Accounting for Pension and OPEB Costs

The OEB began a consultation in May 2015 on rate-regulated utility pensions and other post-employment benefits (OPEBs) in the electricity and natural gas sectors[134]. The objectives of this consultation are to develop standard principles to guide the OEB's review of pension and OPEB costs in the future, to establish specific information requirements for applications, and to consider appropriate regulatory mechanisms for cost recovery which could be applied consistently across the gas and electricity sectors for rate-regulated entities.

Pending completion of this consultation, applicants have been asked to provide information on the recovery method used by the applicant for pensions and OPEBs. Hydro One has indicated that it has historically used a cash based recovery method for pension costs[135] and an accrual accounting based recovery method for OPEBs[136].

Beginning with the Ontario Power Generation Inc. (OPG) Decision in 2014[137], OEB staff notes that pending the outcome of the pension and OPEB generic consultation, the OEB has generally allowed applicants to recover their cash requirements for pension and OPEBs rather than the accrual amount, where the accrual amount is larger and the difference between the two methods is material. This difference is tracked in a variance account in case the OEB decides that the accrual method is the appropriate rate-setting methodology.

In order to make a determination on the materiality of the cash versus accrual differential, OEB staff asked Hydro One Transmission to provide the amount of OPEB costs it has included in rates (pension costs are already being recovered on a cash

[134] EB-2015-0040
[135] EB-2016-0160, Exhibit C1-4-2 p. 1
[136] Exhibit I-1-131
[137] EB-2013-0321 Decision with Reasons, November 20, 2014, p. 87

basis) compared to the amounts actually paid. In its response, Hydro One provided a table that depicts a material difference of $27 million and $25 million between the two methods, for the 2017 and 2018 test periods, respectively.[138] Staff submits that at this time, the OEB should not make a final determination on whether the cash or accrual method should be used for OPEB cost recovery for Hydro One.

In the present circumstances, pending the outcome of the consultation, OEB staff submits that it is reasonable to allow Hydro One to continue recovering their OPEB costs in rates on an accrual accounting on an interim basis for the two test years. The result of the generic consultation is still not known, but information on the public record of the consultation has identified significant complexities with converting to the cash method of recovery as a permanent measure. At the same time, OEB staff submits that it is necessary to establish a variance account that tracks the difference between the accrual method and the cash method for the test years. In this manner, a future OEB panel on Hydro One's next cost-based rate case will have the ability to apply the outcome of the generic consultation, whether that is for Hydro One to remain on the accrual method permanently, transition to the cash method, or adopt some other approach.

With respect to the proposed variance account, OEB staff notes that the OEB has established variance accounts for OPG and other distributors over the past 24 months in circumstances where the cash number is embedded in rates. The difference between the cash method and the accrual method is tracked in the variance account. OEB staff sees no reason why the same approach cannot be followed as an interim measure in this case as well.

Capitalization of Overhead Costs

Effective for their fiscal year beginning on January 1, 2012, Hydro One Inc. received Ontario Securities Commission (OSC) approval to prepare its financial statements in accordance with the accounting principles generally accepted in the United States of America (US GAAP) instead of the accounting principles that are applicable to publicly accountable enterprises in Canada. This approval was sought in response to a mandatory transition to International Financial Reporting Standards (IFRS) by publicly accountable enterprises in Canada as required by the Canadian Institute of Chartered Accountants. In particular, the IFRS standard did not recognize the regulatory assets and liabilities that arose as a result of the OEB's ratemaking policies and decisions, which were recognized under the previous accounting framework in Canada (Canadian GAAP). Receiving approval to use US GAAP as an alternative to IFRS for financial

[138] Exhibit I-1-131

statement reporting purposes enabled Hydro One to preserve the use of these specific rate regulated accounting treatments because they continue to be permitted under the US GAAP standards.

Upon receiving this OSC approval, the OEB then approved an application from Hydro One to use US GAAP as the basis of its rate application filings, regulatory accounting and regulatory reporting requirements instead of the OEB mandated Modified IFRS (MIFRS) framework[139]. In support of the current application, Hydro One provided several examples to illustrate why the OEB and ratepayers would be better off if it used US GAAP instead of MIFRS, including a significant reduction to its revenue requirement and consistency between financial reporting and regulatory reporting,

Most utilities in Ontario are required to follow the OEB mandated MIFRS framework for their regulatory reporting requirements unless approval is received from the OEB to do otherwise.

One of the key differences between MIFRS and US GAAP relates to the types of costs that can be capitalized under each framework. MIFRS, which mirrors the IFRS capitalization requirements, limit the capitalization of costs to only those that are directly attributable to a capital project or asset. Capitalization of an indirect cost is not permitted if a “directly attributable” relationship cannot be demonstrated sufficiently. MIFRS also specifically prohibits the capitalization of certain cost categories like general and administrative overhead costs even if a directly attributable argument can be made. US GAAP on the other hand allows for a more broad interpretation of what types of costs can be allocated to a capital project or asset, therefore making it possible to capitalize indirect overhead costs such as general and administrative costs, as well as other indirect fixed overhead costs that would otherwise not be permissible under MIFRS. However, for rate making purposes, these additional costs are only eligible to be capitalized if the capitalization policy has been approved by the utility’s regulator.

Hydro One updates the useful lives of its assets regularly. It does, in effect, already meet one of the two key requirements for the OEB’s MIFRS standard without actually adopting the formal standard. The one that it does not meet is the more conservative approach to capitalization that is based on the IFRS capitalization requirements, and that all other regulated electricity utilities have adopted irrespective of their accounting standards for financial reporting purposes. OEB staff sees no reason why the OEB cannot approve a less aggressive capitalization policy for ratemaking purposes without affecting Hydro One’s ability to continue to choose the standard under which it reports for financial reporting purposes. This means that in OEB staff’s view, Hydro One should not necessarily be required to adopt other elements of financial reporting that may differ

[139] EB-2011-0268 Decision with Reasons, November 23, 2011

between USGAAP and IFRS, such as how it recognizes gains or losses on disposals. In OEB staff's view, alignment between regulated entities in terms of the expectation to maintain up to date useful lives and a more conservative capitalization practice are the key underpinnings to establishing an equitable foundation for ratemaking across the sector.

Long Term Effects

One of the primary arguments that the OEB considered when approving Hydro One's use of US GAAP for regulatory purposes was the significant impact that it had on the revenue requirement. Hydro One's 2012 transmission revenue requirement was reduced by $195 million as a result of using US GAAP instead of MIFRS as the basis of that rate application. While it is true that the revenue requirement is reduced in the short-term because of US GAAP, OEB staff submits that the ratepayers are in fact worse off over the longer term given that the utility will earn an annual return (debt and equity) in the 6-7% range for the life of the capitalized cost.

Taking a closer look at the main driver of the $195 million reduction to the 2012 revenue requirement shows that it was primarily attributable to approximately $200 million in costs that would have been recognized as OM&A expenses under MIFRS, but instead were capitalized to PP&E (rate base) under US GAAP. This capitalization resulted in an immediate dollar for dollar reduction to the 2012 revenue requirement. However, capitalizing rather than expensing costs only shifts the period in which these costs will be recovered from ratepayers in rates. As a result of the EB-2011-0268 Decision, ratepayers are still responsible for funding the entire $200 million cost balance, however now they are funding it in smaller annual increments through depreciation expense (plus the cost of debt and equity financing) rather than all at once through OM&A expense. In addition, OEB staff submits that over the longer term the ratepayers are in fact worse off because they are being exposed to additional return on rate base for amounts capitalized in excess of what otherwise would be permissible under MIFRS. In the example from the EB-2011-0268 proceeding, ratepayers are now paying a return on rate base for the $200 million over the life of the underlying asset, but would not have been required to pay these amounts had MIFRS been used.

For purposes of Hydro One's current transmission rate application, OEB staff asked Hydro One to estimate what the impact would be on the test period amounts capitalized had their capitalization policy aligned with MIFRS. In their response to this interrogatory Hydro One indicated that under MIFRS they expect that the total capitalization on a consolidated basis at the Hydro One Inc. level would decrease by approximately $310 million[140]. Since this response was provided on a consolidated basis, OEB staff sought

[140] Exhibit I-1-75

additional clarification as to the impact on the transmission business specifically. Based on the related undertaking response provided, Hydro One indicated that amounts capitalized for the test period would be lower by $180 million and $182 million for 2017 and 2018 respectively, with a corresponding increase in OM&A expense[141]. As a direct result of using US GAAP, ratepayers will be paying an additional annual return on rate base over the life of the asset in the form of the weighted average cost of capital in excess of what would have been paid had Hydro One's capitalization policy aligned with the MIFRS requirements.

Mitigation

The OEB has tools at its disposal to mitigate the impacts from a transition to a capitalization policy that is aligned with MIFRS. For example, the OEB could spread the increase to OM&A over a number of years for this first transitional revenue requirement approval. If the OEB was to approve a transition period of 7 years (to potentially align with the two years of this current application and say, a five year Custom IR application to follow), the annual increment to the revenue requirement would be approximately $25 million or 1.6% of the total proposed revenue requirement for 2017 and approximately $50 million or 3.3% for 2018

OEB staff notes that Hydro One's primary motivation for moving to US GAAP was to preserve the use of specific regulatory assets and liabilities that were not recognized under IFRS. Since that time, IFRS released a new standard, IFRS 14, effective for fiscal years beginning on or after January 1, 2016, that now permits the use of these rate regulated assets and liabilities for financial statement reporting purposes.

OEB staff notes that there are current examples of utilities that were granted OEB approval to use a regulatory reporting framework other than MIFRS, but were still mandated to align their capitalization and depreciation policies with MIFRS requirements. One such example is Canadian Niagara Power Inc. They were granted approval to use Accounting Standards for Private Enterprises as the basis for their regulatory reporting but were still required to adopt the OEB's MIFRS capitalization and deprecation policies as part of that reporting. OEB staff submits that a similar approach can be taken with Hydro One. This should provide ratepayers with longer-term cost benefits (lower return on rate base) and also put Hydro One on equal footing with the other utilities in Ontario.

[141] Undertaking J11.21

IPO Tax Benefits

In November 2015 Hydro One completed an Initial Public Offering (IPO) totaling approximately 15% of its common shares. Up to the date of the IPO, Hydro One was a tax exempt corporation under both the Federal and Ontario Tax Acts. They were instead required to make Payments in Lieu of Taxes (PILs) to the Province of Ontario as dictated by the Electricity Act.

The Electricity Act also imposes a departure tax (or exit tax) on publicly owned utilities once the utility ceases to be tax exempt (i.e. exits the PILs regime). A utility loses this exemption when it disposes of more than 10% of its assets to the private sector as prescribed by the Federal and Income Tax Act. Due to the IPO, Hydro One lost its tax exempt status because more than 10 percent of the company is now owned by private investors and therefore it became subject to the departure tax in the Electricity Act.

The departure tax itself is calculated on income that is created by a deemed disposition of the company's assets, which occurs immediately prior to losing this tax exempt status. A deemed disposition effectively revalues a utility's assets to their fair market value for tax reporting purposes, but has no impact on the accounting book value or rate base for regulatory purposes. As a result of losing its tax exempt status, Hydro One incurred a $2.6 billion departure tax that was paid to the Ontario Electricity Financial Corporation. This tax liability was funded by way of an equity issue to the Province of Ontario (the shareholder) in which the province provided Hydro One with $2.6 billion in return for an equivalent amount of shares.

The deemed disposition of Hydro One's assets also resulted in a deferred tax asset, which represents deductions that can be used to reduce taxable income in future periods. These deductions are primarily derived from the difference between the tax value and accounting book value of the company's assets. In particular, the bump in the tax cost of Hydro One's depreciable assets allow it to claim higher capital cost allowance deductions in computing income for tax purposes. Based on the details in Hydro One's 2015 Annual Report, Hydro One realized a $2.6 billion future tax asset[142] as a result of this deemed disposition, of which approximately $1.48 billion related to the transmission business[143].

For purposes of its transmission application, Hydro One has excluded the revenue requirement impact of both the departure tax and the deferred tax asset.

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[142] The $2.6 billion figure reflecting the amount of the departure tax and the value of the future tax asset is a rounding coincidence. The exact amounts for each are actually different.
[143] Exhibit I-1-134

Stand Alone Principle

In response to OEB staff interrogatory #134, and through further details provided during cross examination, Hydro One indicated that one of the primary motivations for excluding both the departure tax and deferred tax asset from rates was to adhere to the “stand alone” principle of ratemaking. This principle essentially isolates the operations of the regulated utility so that only the costs from activities related to the provision of services to ratepayers are considered in the determination of the revenue requirement. OEB staff submits that the shareholder’s decision to pursue an initial public offering of a portion of its shares had nothing to do with the operation of the regulated entity or the provision of services to ratepayers. There was no cost to ratepayers. Therefore the stand-alone principle would dictate that these activities should not impact the rate making process.

Hydro One further contends that since they have incurred a real cost in the form of a departure tax, and have not included this cost in the determination of rates, then they should also be entitled to receive the related benefits of the deferred tax asset.

Benefits Follow Costs

Staff agrees with Hydro One. The company has incurred a departure tax that has not and will not be recovered in rates. Ratepayers have not paid the cost that resulted in the deferred tax asset, and should therefore not receive the benefit. On the principle that benefits should follow costs, the shareholder should be entitled to the resulting benefit.

OEB staff notes that the RP-2004-0188 Decision[144] addressed a similar matter with respect to the allocation of deferred tax benefits that arose upon a utility’s entrance into the PILs regime in 2001. In that case, utilities were deemed to have disposed of their assets at fair market value, which resulted in a significant deferred tax asset. The OEB sought to determine whether this asset should go to the benefit of the ratepayer or the utility. In that Decision, the OEB ruled in favour of the ratepayers on the basis that the shareholder had not incurred a cost as a result of the transaction, and therefore no harm was being done to the utility by passing these benefits onto the ratepayers. However, in the case of the departure tax, Hydro One did incur a cost to create the benefit, and to pass the benefit through to ratepayers would create harm to Hydro One.

-All of which is respectfully submitted-

[144] Report of the Board on the 2006 Electricity Distribution Rate Handbook, May 11, 2005