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February 16, 2017

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, Ontario M4P 1E4

Dear Ms. Walli:

Re: EB-2016-0160 Hydro One Networks Inc. – Reply Argument

In accordance with the Ontario Energy Board's letter dated February 3, 2017, enclosed please find Hydro One Networks Inc.'s Reply Argument in respect of the above matter.

Yours truly,

McCarthy Tétrault LLP

Gordon M. Nettleton

GMN/mpf
Enclosure

ONTARIO ENERGY BOARD

IN THE MATTER OF a cost of service application made by Hydro One Networks Inc. Transmission with the Ontario Energy Board on May 31, 2016 under section 78 of the *Ontario Energy Board Act,* 1998, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to its transmission revenue requirement and to the Ontario Uniform Transmission Rates, to be effective January 1, 2017 and January 1, 2018 (the "Application");

OEB PROCEEDING EB-2016-0160

APPLICATION BY HYDRO ONE NETWORKS INC.
FOR APPROVAL OF TRANSMISSION REVENUE REQUIREMENT

REPLY ARGUMENT OF HYDRO ONE NETWORKS INC.

February 16, 2017

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I. INTRODUCTION

1. Hydro One Networks Inc. ("Hydro One") has received submissions from Board Staff ("Staff"), Anwaatin Inc. ("Anwaatin"), the Association of Major Power Consumers in Ontario ("AMPCO"), the Building Owners And Managers Association, Greater Toronto ("BOMA"), the Canadian Manufacturers & Exporters ("CME"), the Consumers Council of Canada ("CCC"), Energy Probe, Environmental Defence ("ED"), Hydro Québec Energy Marketing ("HQEM"), the London Property Management Association ("LPMA"), the Power Workers' Union ("PWU"), the School Energy Coalition ("SEC"), the Society of Energy Professionals ("SEP") and the Vulnerable Energy Consumers Coalition ("VECC").

2. Hydro One's reply submissions are organized to address and follow the matters found in Staff submissions. Additional topics addressed by intervenors follow.

II. REPLY ARGUMENT

A. <u>TRANSMISSION SYSTEM PLAN AND CAPITAL EXPENDITURES</u>

<u>Introduction – Transmission System Plan and Capital Expenditures</u>

3. The central issue in this proceeding is whether Hydro One's Application has provided sufficient information to demonstrate that the costs it expects to incur during the test year period are reasonable. Under cost of service rate regulation, rates must allow the utility the opportunity to recover, over the long run, its operating and capital costs through rates so long as they are reasonable or prudent.[1] [2]

4. The onus lies with Hydro One to provide evidence to demonstrate that its forecast costs are reasonable. Where the reasonableness standard is met, the regulator must allow the utility the opportunity to recover them through rates. Assessing the reasonableness of forecast costs must take into account all relevant evidence. While the Board has discretion to use a variety of analytical tools in assessing the justness and reasonableness of a utility's forecast costs, this discretion is not absolute or *carte*

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1 *Northwestern Utilities Ltd v City of Edmonton*, [1929] SCR 186 at 192-193.

2 *Ontario Energy Board v Ontario Power Generation*, 2015 SCC 44 at para 16 ("***OPG***"); *ATCO Gas and Pipelines Ltd v Alberta (Utilities Commission)*, 2015 SCC 45 at para 7 ("***ATCO***").

blanche.[3] The exercise must be demonstrated to strike a balance of fairness by limiting a utility's recovery to what it reasonably or prudently costs to efficiently provide the utility service. In other words, the regulatory body ensures that consumers only pay for what is reasonably necessary.[4]

5. Thus, the overarching question for the Board to determine is whether Hydro One's evidence demonstrates that recovery of its forecast costs is reasonably required to provide the utility service during the test years. Conversely, the Board must ask whether there is sufficient evidence to demonstrate that Hydro One's forecasts costs are not reasonably required during the test year period in order for the efficient provision of transmission services.

6. Comparisons to prior periods and an apparent general sentiment that Hydro One's proposed investments are "too high", combined with general concerns regarding electricity rates in Ontario, appear to underlie, if not form the basis for, the submission of several intervenors as well as that of Staff[5] - that Hydro One's proposed capital expenditures should be reduced, despite the clear evidence that Hydro One has put forward which demonstrates that these investments are needed. Comparisons to prior periods, by themselves, do not provide a reasonable basis to justify the rejection of applied-for prospective expenditures. Such a comparison does not address why the evidence that Hydro One relies on, namely factual evidence of asset condition and the costs necessary to address those concerns in order to provide transmission service efficiently, is outweighed by historical comparison.

a) Sustainment Capital - The Proposed Sustainment Capital Budget Has Been Fully Justified

7. While Energy Probe largely supports the capital components of Hydro One's Application,[6] Staff and several intervenors argue that Hydro One's capital budget should not be approved and should be reduced. Staff's submissions recommend reductions totaling $136M. Even greater reductions are proposed by AMPCO, SEC and CCC.

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3 *OPG* at para 104.

4 *OPG* at para 20; *ATCO* at para 63.

5 This is apparent in Staff's discussion of tower coating, when Staff notes that while it appreciates that Hydro One has made efforts to identify opportunities to optimize spending, "it is also true that electricity customers in Ontario are very concerned about rising electricity bills." See Board Staff Submissions, Page 7.

6 Energy Probe Submissions, Page 3.

8. Staff's submission states that reductions are based on three reasons:

- Capital spending on sustainment projects has not been fully justified;
- The TSP and evidence filed in support of the capital spending was insufficient to demonstrate "value to customers"; and
- Customer engagement activities in respect of this Application were inadequate.

9. Hydro One disagrees with these propositions, which are similar to propositions also raised by intervenors. Hydro One's supporting evidence appropriately justifies all of its capital expenditure projects and programs, and in particular, the tower coating and integrated station investment programs. Criticism regarding inadequate evidence or inadequate justification for a particular capital asset investment must be carefully considered. No evidence has been submitted to challenge Hydro One's evidence and reasons. Hydro One's forecast investments and costs are supported by objective third party condition assessments that were not seriously challenged during the hearing process; nor did intervenors or Staff file evidence that undermined the credibility of these objective, third party reports.

i) Lines Investment

Conductors

10. Staff agrees with Hydro One's proposed spending in regards to work on conductors, noting that "[t]he evidence of Mr. Ng during the oral hearing was persuasive that the proposed work on conductors is needed."[7]

11. AMPCO raised concerns over the change in the proposed conductor replacement program as compared to Hydro One's last application. AMPCO suggests that equipment performance improvement over the past ten years related to conductors is a sound basis to maintain a 15 year plan to replace high risk transmission conductors. AMPCO's comments do not address the underlying justification provided by Hydro One for the proposed conductor program increase: testing results revealed larger populations of high risk conductors. Nor does AMPCO consider the impacts of carrying line

[7] Staff Submissions, Page 6.

refurbishment backlogs into future years. Proposed reductions of $81 million have not been demonstrated to be based on asset condition evidence, but rather, assumptions that status quo historical replacement rates are appropriate to address end of life conditions that now are known to exist. Changes in pacing are necessary and demonstrated accordingly.

12. SEC suggests that proposed sustainment investments are unreasonable because of significant problems with the reliability risk model, insufficient justification for capital programs and lack of productivity built into the capital spending program.[8] Application of the reliability risk model is not the basis that Hydro One relies on for its proposed capital investments. As it relates to conductors, Hydro One's justification was not reasonably shown by SEC to be insufficient or that a lack of productivity has been built into capital spending programs.

Tower coating

13. Staff and a number of intervenors suggest that Hydro One's proposed increased investment in tower coating should be reduced. Staff's view that there is inadequate justification for Hydro One's proposed test year Lines sustainment expenditures is focused exclusively on the tower coating program. The basis set out in Staff's submission for the proposition that tower coating investments should be reduced is threefold:

(1) Mr. Ng's testimony that the proposed tower coating program does not address short or medium term threats to reliability relative to the other sustainment investment programs (conductors and insulators);

(2) Tower coating only addresses an economic opportunity to defer significantly higher capital expenditures associated with tower replacements; and

(3) Immediate bill impacts should outweigh the longer term value associated with tower coating programs.

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8 SEC Submissions, Pages 25-27.

14. It is true that from a system reliability perspective, end of life conductors and defective insulators have a greater priority to professional transmission system planners.[9] However, this does not in any way eliminate the need for asset life extension and lower cost tower coating programs, particularly as compared to the alternative of "doing nothing" and then bearing higher costs of refurbishment and replacement. In other words, economic benefits to ratepayers should not be disregarded because there is no short or medium term risk to reliability if Hydro One does less tower coating.

15. Staff asserts that "no near term risk to reliability" or "significant loss of economic benefit" are appropriate grounds for substantially reducing the tower coating program. LMPA and SEC make similar suggestions.

16. What is unclear from these criticisms is the level of "significant loss of economic benefit" that Hydro One must demonstrate before these programs would be considered permissible, or at least not be substantially reduced. This is important because Staff and intervenors have not suggested Hydro One forego the tower coating program in its entirety. Instead, Staff and intervenors have argued that the capital expenditures associated with the tower coating program should be reduced. Staff have not demonstrated or provided a principled framework for determining the appropriate cut-off point for the quantum of investment in tower coating that should occur, and as such, the level of investment proposed by Staff cannot be tested by Hydro One and its experts. Hydro One's evidence relating to the size and scope of its tower coating investment is driven by objective, asset condition information and should not be assessed from the point of view of unknown and untested standards that are not reflective of asset condition.

17. What is also unclear with respect to Staff's immediate benefit reasoning, is how any program intended to address preventative maintenance or asset life extension – situations that prevent far greater costs in the future – could meet a "near term benefit"

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[9] Mr. Ng's response to questions regarding which of the three main Lines investment initiatives was the least important must be placed into proper context. Mr. Ng was not asked whether the tower coating program was in some way, superfluous, or unnecessary or what consequences would arise if the proposed program was delayed beyond the test years. He was asked only to rank the relative importance of the three sustainment capital expenditure programs as they related to immediate system reliability concerns. See Transcript Volume 5, Page 180 [emphasis added]: Ms. Lea asked Mr. Ng, "[considering] these three large programs in the lines area, the replacement of the insulators, the conductor replacement, and the tower recoating, can you rank them for us in terms of their **importance to system performance and public safety risks**? Which would be the most critical or important?" Mr. Ng. replied "It is a tie for the first place, the insulator replacement and end of life conductor. And tower coating comes second or third."

standard, particularly in an industry with assets that have long service lives. Feedback and criticisms received from the IPSOS customer engagement process (the "IPSOS Engagement") were that Hydro One needs to pay more attention to addressing situations today that can provide greater reliability and lower costs in the future. Working smarter, paying more attention to the long-term was a common view.[10] Staff's "immediate benefit" reasoning conflicts with these observations. It would be difficult to see how any preventative maintenance or asset life extension program where costs are incurred today to avoid far greater costs in the future would be able to meet Staff's new standard. Furthermore, the proposed focus on immediate benefits appears inconsistent with the longer term view planning horizons and the trade-offs that are enabled and encouraged under the Board's Renewed Regulatory Framework and adoption of Transmission System Plans.

18. The real and tangible nature of avoided future costs associated with the tower coating program is demonstrated in the Application. Avoiding significant costs in the future through the tower coating program is the objective. Doing so will provide economic benefit and value to customers because a relatively small investment now will result in large savings to customers in the future. Tower coating program is an exemplary investment that considers repair versus replace options. In this case, repairing the asset by applying coating, which extends asset life, is clearly the preferred option that results in a significant present value positive investment.[11]

19. Consider Investment Summary Document S62, (Circuits C22J/C24Z/C21J/C23Z) which sets out a $51M investment to refurbish 285 structures.[12] Refurbishment of 285 structures represents more than the proposed cost of the tower coating program in 2017, and yet the proposed tower coating would provide almost ten times the benefit in terms of the number of towers (1250 towers proposed to be coated in 2017). Had the new coating technology been available and applied before these structures had reached their current condition, the S62 investment could arguably have been avoided or at least reduced. The cost of coating would have been multiple times lower than the cost that is now required to refurbish the towers. A proactive step to prevent higher cost repairs is a reasonable approach to investment planning. The proactive adoption of new

[10] Exhibit J4.7.

[11] Exhibit TCJ 2.3; Exhibit J5.4.

[12] Exhibit B1, Tab 3, Schedule 11, S62.

technologies/products that prolong tower life is clearly an example of investing smarter to reduce future rate impact. Consequently, curtailment of such a net present value positive asset life extension investment program should not be the objective; rather the goal should be to ensure maximum benefit throughout the system is achieved.

20. Extensive evidence regarding Hydro One's tower coating program was provided prior to the oral stage of the hearing process.[13] The pace of the tower coating program was the result of new information coming to light subsequent to Hydro One's last rates application: (1) new coating technology; and (2) objective study of the number of towers at risk in high corrosion areas in the province.[14] The program was described throughout the Application.[15] The gross investment cost of the proposed tower coating program is $42.5 million in 2017 and $54.4 million in 2018.[16] Additional details and copies of expert reports justifying the scope of the program were provided in the interrogatory process.[17] During the Technical Conference, Staff and intervenors had the opportunity to ask questions and seek undertakings regarding the need, scope and pacing of the program.[18] While it was evident that Staff accepted that the tower coating program is an opportunity to employ new and inexpensive technology to extend the life of valuable and relatively expensive capital assets, the issue appears to be need for and scope of the proposed program and the pace during the test years.

21. The Electric Power Research Institute report[19] ("EPRI Report") is the starting point to understand the objective facts justifying the tower coating program. The Electric Power Research Institute ("EPRI") identified the most corrosive geographic regions in the Province. It did so using established methodologies. Specifically, the population of the most susceptible towers within high corrosion regions that would benefit most from tower coating was identified,[20] based on an extensive survey of 100 tower structures and by

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13 Exhibit B2, Tab 2, Schedule 2, Attachment 1, Slides 14 and 22.

14 Technical Conference Transcript Volume 2, Pages 71-72.

15 Exhibit B1, Tab 3, Schedule 2, Page 36; Exhibit B1, Tab 2, Schedule 6, Pages 44-54; Exhibit B1, Tab 3, Schedule 11, Attachment 1, Reference S76.

16 Exhibit B1, Tab 3, Schedule 11, Attachment 1, Reference S76. Notably, if the tower coating program was eliminated entirely, this would only account for 36% of the overall annual capital expenditure reduction recommended by Staff.

17 Exhibit I, Tab 9, Schedule 6.

18 Technical Conference Transcript Volume 1, Page 139.

19 Electric Power Research Institute, "Atmospheric Condition Assessments of Hydro One Structures Population Assessment Practices and Results".

20 Exhibit I, Tab 9, Schedule 6, Attachment 2: EPRI Report.

conducting condition assessments on each structure. EPRI's survey results possessed a confidence level of 95% with an error rating of 9.65%.[21] Using a minimal accepted coating standard (a thickness threshold of 1.65 mils), modeling results revealed that 13.88% of all Hydro One's structures (which number 55,000) require a re-coating measure. If that reject criteria was increased to 1.95 mils (an 18% thickness increase), EPRI found that the tower population requiring coating would almost double from 13.88% to 23.9%.[22]

22. Based on the EPRI Report, the evidence is that there are approximately 13,000 towers located within high corrosion zones. Of these, 7,550 towers have met EPRI's criteria establishing the need for coating, namely, corrosive region, having less than a minimal remaining coating thickness level and having reached an age that is optimum to apply coating to extend asset life.

23. None of these objective facts or conclusions were found to be lacking during the oral hearing. Little, if any regard to these facts is given in arguments that challenge the tower coating program.

24. Hydro One's professional judgment and experience was then applied to addressing this population. Hydro One did so by concentrating on only 60 percent of the 7,550 tower population over the next 5 years (i.e., 4,530 towers). The 60 percent factor was not arbitrary. Rather, this sub-set of the tower population not only meets all of EPRI's characteristics noted above, but in addition, these are the towers that are actually experiencing corrosion and metal loss. As Mr. Ng noted the risk with this sub-set of the population is that they are the ones most likely to be candidates for costlier refurbishment if they are not addressed now. For these towers, the time for coating is now.[23] This demonstrates the consideration that Hydro One staff applied to develop a reasonably paced plan.

25. A criticism repeatedly found in Staff's argument and the argument of other intervenors is that Hydro One has paid little regard to the pacing and timing of investments.[24] Hydro One disagrees with this assertion and again refers to the evidence on the record relating

21 EPRI Report, Page 33.

22 EPRI Report, Page 28.

23 Technical Conference Volume 2, Pages 71-72.

24 Staff Argument, Page 11 is one example.

to the pacing of the tower coating program. The evidence is that the program will span a five year period. Hydro One's plan is to appropriately pace the proposed investment program, such that 1,250 towers (28% of 4,530) are coated in 2017 and 1,600 towers (35% of 4,530) are coated in 2018. The remaining 1,680 towers that are affected by corrosion and metal loss (i.e. 37% of 4,530) will be addressed post-2018. This means that 2,850 towers or only 38% of the total 7,550 tower population will be addressed during the test period. The balance (i.e., 4,700 towers or 62% of the total 7,550 tower population) will be re-coated beyond the test period.[25]

26. There is no dispute that the proposed level of investment in this Application is higher than historical levels. This does not, however, mean that the proposed tower coating program is inappropriately paced; the need for higher levels of investment is supported by the evaluations and conclusions contained in the EPRI Report. If historical investment levels are not increased, the outstanding population grows disproportionately. Hydro One's evidence addressed this point. Maintaining historical investment levels means that an additional 4,700 steel structures will meet tower coating criteria over the next 10 years.[26] This result imposes greater risk upon the time period to address towers already identified as having corrosion and metal loss and also the risk that towers become assets requiring more expensive refurbishment options; these populations and risks are based on a minimum rejection coating thickness standard of 1.65 mils. If a higher rejection standard is used (i.e., 1.95 mils) the population becomes far greater.

27. While the scope of the EPRI Report did not extend to an assessment of Hydro One's proposed pacing of the tower coating program, the question is why that should be necessary. Pacing is a question best answered by the owner and operator of the assets and the ability to judge work execution limits. This experience and judgment has appropriately been used in these circumstances. Asset condition assessment, capacity to undertake work, and the total population of towers requiring remediation/coating are the drivers of appropriate pacing. Consideration was given to the rate consequences. Avoiding investment today exacerbates the quantum of investment in the future and drives higher future rates, which is contrary to the public interest.

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[25] Exhibit B1, Tab 2, Schedule 6, Pages 47-49; Exhibit I, Tab 1, Schedule 70.

[26] Exhibit B1, Tab 2, Schedule 6, Page 47, Lines 11- 18.

28. Finally, Staff suggest that the immediate bill impact outweighs the value of the proposed tower coating expenditures. Yet exactly what level of that bill impact causes the program to exceed an acceptable level has not been explained.

29. Hydro One's evidence is that it took bill impacts into account when preparing its application because customer needs and preferences were a vital objective. The best evidence of moderating total bill impact is cited by Staff and most intervenors: the Application proposes a 0.1% and 0.2% increase in total rates for medium residential density customers in 2017 and 2018. For transmission connected customers, the total overall increase is 0.2% and 0.4% during the test years. The best evidence of customer needs and preferences, particularly as it concerns rate increases, is seen in the customer engagement exercise where bill increase levels, overall capital expenditures, and changes in system reliability risk were all considered by transmission customers during three different rounds or waves of engagement. The outcome of that engagement was that customer needs and preferences were in alignment with Hydro One's proposed investments and resulting total bill impact levels. Neither Staff nor any other party have provided evidence to the contrary, namely, that a majority of transmission customers dispute the results of the customer engagement exercise, let alone have concerns with the proposed bill increases or that the tower coating program, as proposed, is somehow a poorly planned investment.

30. The development and proposed execution of the tower coating program are based on objective facts. The tower coating program is appropriately paced and supported by asset condition, and provides a clearly demonstrated future benefit to customers. Hydro One submits there is no rational basis justifying expenditure reductions to the tower coating program.

ii) Stations

Stations Sustaining Investments - Introduction

31. The 2017 and 2018 transmission station investments concern work required to refurbish or replace existing assets within transmission stations, including transformers, breakers, protection, control and telecommunication assets.[27]

[27] Exhibit B1, Tab 3, Schedule 2, Page 1.

32. The overall cost breakdown of all proposed transmission station investments was provided in Exhibit B1-3-1-1. Total Transmission Stations Capital is proposed to decline slightly in the test years from 2015 and 2016 levels. Maintaining station investment levels near 2015 and 2016 levels is necessary so that Hydro One can continue to address end of life or near end of life asset conditions. The projects involved are not discretionary, but rather address assets that are at high or very high risk of failure. As Mr. Penstone explained, if work is deferred the problem is compounded: "You are compounding the amount of work that we have to do and the execution challenges to execute larger amounts of work in future periods."[28]

Schedule 1
Attachment 1
Page 1 of 3

COMPARISON OF NET CAPITAL EXPENDITURES BY MAJOR CATEGORY–
HISTORIC, BRIDGE AND TEST YEARS

Transmission Capital ($millions)	2012	2013	2014	2015	2016	2017	2018
Sustaining Capital							
Transmission Stations							
Circuit Breakers	11.2	23.4	25	7.1	2.4	1.1	0
Power Transformers	78.4	87	111.1	43.5	8.9	0	0
Other Power Equipment	28.3	26.5	27.5	12.5	4.5	0	0
Ancillary Systems	16.4	15.6	22	17.1	5.2	1.3	0
Station Environment	7.6	6.6	10.5	3.8	1.3	0	0
Integrated Station Investments	62.1	89	157.3	374.2	454.4	457.8	404.7
Tx Transformers Demand and Spares	0	0	0	27.2	20.5	25.3	25.8
Protection and Automation	95	84.4	97.9	60.2	45.6	45.2	59.1
Site Facilities and Infrastructure	23.4	22.9	30	20.3	9.4	6.7	6.7
Total Transmission Stations Capital	**322.5**	**355.3**	**481.3**	**565.8**	**552.2**	**537.5**	**496.2**

33. The forecast total Transmission Stations Capital investment forecasts were the subject-matter of ongoing evaluation. Exhibit J9.02 provided information regarding the changes in the forecast levels that were made to accommodate the need for incremental lines investments due to new testing results that confirmed deteriorating conductor condition. The result has been incremental deferrals are embedded in this Transmission Stations Capital Investment. Hydro One has done so in order to accommodate these needs and to minimize bill impacts.

34. Integrated station investments make up the large majority of station investments. This category reflects changes that Hydro One has instituted since 2014 whereby planning

[28] Transcript Volume 2, Page 11.

and work execution group similar end of life or near end of life assets found at individual station properties. The transition in work execution strategy is reflected in the proposed funding increase in Integrated Station Investments and consequent reductions in other asset-specific investments. This approach minimizes work crew deployments and multiple planning and engineering exercises that would otherwise be necessary using the older execution strategy. The approach is also highly beneficial to ratepayers and customers because more work can be performed at a lower cost and with fewer outages. Exhibit B1-3-2 page 7 stated the savings estimates: $57 million in avoided capital costs and $2 million in OM&A savings. These estimates were tested during the interrogatory and oral hearing process. Exhibit I-1-62 stated the savings were directly attributable to the reduction of 10 power transformers and 24 breakers. Exhibit I-1-65 provided further information regarding the OM&A savings. Savings were calculated using present value analysis of the operating costs Hydro One would have expected to incur over the life of the assets that are being eliminated within three cost categories: Preventative Maintenance, Corrective Maintenance and Transformer Refurbishment.

35. Hydro One's evidence provided further detail of the three main programs within the Integrated Station Investments category of the Station Investments. These were summarized in Table 3 of Exhibit B1-3-2, page 12.

Table 3: Integrated Station Investment Projects ($ Millions)

Description	Historic Years				Bridge Year	Test Years	
	2012	2013	2014	2015	2016	2017	2018
Air Blast Circuit Breaker Replacement Projects	22.4	17.9	28.0	80.5	95.9	95.1	109.4
Station Reinvestment	27.0	39.7	31.1	61.5	61.4	101.5	109.5
Integrated Station Component Replacements	(3.3)	30.6	97.7	229.2	297.1	261.3	185.7
Other Historical Projects	16.0	0.8	0.5	3.0	0.0	0.0	0.0
Total	**62.1**	**89.0**	**157.3**	**374.2**	**454.4**	**457.8**	**404.7**

36. The Air Blast Circuit Breaker ("ABCB") Replacement Program is a continuation of the program conducted in prior years. ABCBs are the poorest performing breakers in the

system,[29] and have the highest operating costs of any breaker technology. The challenge associated with this type of breaker, which tends to be installed at major stations such as Beck 2 and Bruce A,[30] is that there are often approximately 20 of these breakers at a given major station.[31] Moreover, planning the necessary outage is a challenge because synchronizing such outages with generators is necessary.[32] The result of this is that ABCB replacement is a complex undertaking which takes four to five years to complete.[33]

37. Station reinvestment is also a carryover from previously approved sustainment expenditure programs. These projects address the need to reconfigure stations when end of life or near end of life assets are replaced. By using standardized designs to reconfigure station assets when major refurbishments are needed, Hydro One is achieving efficiencies and savings that benefit ratepayers in the long term. The scope of the integrated station component replacements is described in Exhibit B1-3-2 page 14-16.

38. The Integrated Station Component Replacements program involves Hydro One examining end-of-life and near end-of-life assets in order to determine optimal work plans. By reducing the number of times that work must be carried out within a station property, Hydro One can provide a benefit to customers because the number of outages is reduced. Reducing outages lessens the risk of downtime to customers and greater costs to their operations. As Mr. Penstone described "it's not only in terms of the capital efficiencies of undertaking the work as a bundled exercise, but another key consideration behind this approach is to mitigate or manage the consequences to our customers as well."[34]

39. Staff and intervenors make a number of arguments to support a lower level of stations investment. These are addressed in turn below.

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[29] Exhibit B1, Tab 3, Schedule 2, Page 12, Lines 7-8.
[30] Transcript Volume 7, Pages 109-110.
[31] Transcript Volume 7, Pages 106-107.
[32] Transcript Volume 7, Pages 109-110.
[33] Transcript Volume 7, Page 106.
[34] Technical Conference Volume 2, Pages 43-44.

Relationship Between Equipment Failures and Customer Outages

40. One of Staff's arguments in support of lower investment in stations is to point out that equipment failure at stations account for only a small portion of outages suffered by customers.

41. Hydro One's evidence is that station investments are needed because the targeted equipment has reached its end-of-life or near end-of-life condition. Deteriorating asset condition, not outage history, is the driver for investment decisions. If transmission planning was based on lagging indicators, such as the number of customer outages, the exercise would be entirely reactionary. No regard to asset condition would be necessary because investment would only be made once failures and outages had happened. Such an approach would be the antithesis to good transmission system planning. What experienced transmission planning professionals are trained to do is avoid outage consequences and they do so by making asset investment decisions based on objective facts, namely objective asset condition assessments before failures happen.

42. Mr. Penstone explained why not all equipment failures result in customer outages. The design of the critical transmission system in the southern part of the province that is the backbone for all critical industry and residents, provides redundancy through multiple circuits. However, reliability from redundancy is reduced when equipment fails. When that happens the remaining assets that provide redundancy are then left to do the full job, significantly increasing risk to a critical system. It is important to note that those assets that remain in service and provide the functionality of the failed assets are, in most cases, of similar age and condition of the assets that have failed and can no longer provide service. Relying on redundancy to avoid or defer equipment replacement due to asset condition compromises system performance and introduces additional risks which planners seek to avoid. "Run to fail" is an unacceptable management practice with these types of assets.

43. The benefits of investment must not be confused with the root cause and justification for investments. The fundamental issue Hydro One continues to address with multi-year station investment programs is end of life asset condition. This problem is not related to Hydro One's station-centric approach. Asset condition is a fleet-wide issue. Asset deterioration arises as a result of the original in-service timing of assets, a focus on

development rather than sustainment capital programs in previous years, and the backlog of assets at or near end-of-life. This backlog will continue for some time because Hydro One is in no position to address all end-of-life assets during the test year period.

44. By suggesting that the proposed expenditures are not fully justified and that arbitrary reductions should be made, Staff are asking Hydro One to knowingly allow equipment failure risk to increase by not replacing known end-of-life or near end-of-life assets. Hydro One does not agree with this proposition because there was no evidence provided in this proceeding that suggests Hydro One's reliance on the assessment reports filed in conjunction with this Application and on the approach used to assess asset condition is wrong.[35] Asset investment based on condition is entirely consistent with the Board's approach.

45. That the proposed expenditures have benefits, namely, reducing risks of future customer outages is positive. Improved reliability and reduction in risk is an outcome of new investment. To suggest a new asset is not justified because outages have not been sustained, does not say anything about the underlying rationale for the investment – a deteriorated asset condition. Hydro One submits any critical assessment of its Stations Investment program, should be focused on this underlying rationale.

Spending Level Comparison as Justification for a Reduction

46. Staff's assertions on this subject focus on a comparison between Hydro One's Stations expenditure levels in 2012 and the test year period. However, no explanation is given why 2012 is the correct year to compare test year expenditures, and more specifically, how such a comparison is relevant to the assessment of Hydro One's end-of-life or near end- of-life condition justification for Station Investments.

47. Staff appear not to place weight on the fact that Total Transmission Stations Capital Investment levels actually decline in each of the test years as compared to 2015 and 2016 levels. These more recent years provide a better comparative reference level, as many of the programs comprising the Integrated Systems Investment category are multi-year – ones in which the investment programs commenced in the 2014/15/16 period and

[35] See Interrogatory Response to Staff IR 31.

are proposed to continue into the test years. Investment programs that were initiated in the 2014 to 2016 years based on asset condition continue to be valid programs in the 2017 and 2018 test years, based on asset condition. Mr. Penstone confirmed this during his testimony.[36] Reducing these programs would mean programs that have started would stall or be forced to stop before being completed. Sunk costs would result and additional costs would be necessary in the future to put the projects as they now are back into place. No objective evidence has been provided to suggest the underlying reasons and justifications for these programs have changed. Indeed, more work is proposed, not less, as compared to these prior periods. Mr. Ng also explained this point clearly.[37]

Pacing of Station Investment given upcoming nuclear refurbishment

48. Parties have questioned Hydro One's indication that it must take into account the upcoming outages of baseload nuclear generation scheduled to take place in Ontario. Staff asserts that the timing of station investment is premature without detailed discussions with Bruce Power, OPG and the IESO because actual limitations are unknown.

49. First, Hydro One observes that it is important not to misconstrue the principal reason for the station investments: condition-based need. The proposed investments are sustaining and not development expenditures. They are based on the existing end of life or near end of life condition of station assets[38].

50. Second, Hydro One submits that it does need to take into account upcoming baseload nuclear outages because when generation from nuclear facilities is down, greater

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[36] Transcript Volume 1, Page 104.

[37] Transcript Volume 6, Page 127 at Line 13 to Page 129 at Line 4.

[38] Board Staff asked Mr. Penstone, "Is it prudent at this time to accelerate some of your work, given that you don't yet have the information from the IESO with respect to this?" Mr. Penstone replied, "We are actually not proposing to accelerate work. We are proposing to undertake activities to address assets that are at their end of life. It's not a question of acceleration. We have knowledge, and we have the technical assessments that tell us we have assets that need to be replaced. So we have two choices. We can either replace the assets, or we can defer the replacement and hope that they don't fail.

Asset managers and professional engineers don't like to rely on hope. And what our asset risk metric does is basically say here is the risks that you are taking if you hope the assets don't fail.

The plan, the transmission system plan that we have developed today is the one that -- Mr. Ng's group comprises over 60 engineers and asset managers. That is their recommendation and our recommendation in terms of not only the need to do the work, but the need to do it now to be in sound order to enable the province to accommodate these nuclear outages." See Transcript Volume 5, Pages 156-160.

reliance will be placed on other portions of the system to meet all system requirements and outages will be more difficult to secure.[39] Moreover, if investments are made now, existing programs that are already in progress are able to proceed to completion. As Mr. Penstone mentioned, as it relates to breakers and transformers, there has been no new compelling information about the state and condition of these assets to change the pace and levels of the investments at the stations.[40] Greater system reliability is created allowing the grid to better address major base load generation unavailability. Waiting simply imposes unnecessary risks – particularly when many of the station programs are mid-stride and investment dollars are needed for their completion.

51. Hydro One notes that it did have discussions with both Bruce Power and OPG with respect to Bruce Power and OPG's schedules for refurbishment, and that Hydro One has raised the refurbishment schedule issue with the IESO.[41]

<u>Stations Sustainment Investment May be Deferred because it is for Load Serving Stations</u>

52. At page 8 of its submissions, Staff present figures that recast the quantum of the proposed Stations Sustainment investment into "generation", "load", or "both" categories. What Staff suggests is that because $220 million of Station investment is proposed to be made at stations serving load, a reasonable inference can be made suggesting all of this investment may be deferred as none will cause "any concerns for co-ordination with nuclear refurbishment". [42]

53. Hydro One's concern is the sustained unavailability of base load generation will place a much higher reliance on the sustained availability of the remaining generation. Staff's assertion that a sustained unavailability of base load generation won't affect load stations is incorrect. Any transmission path for the generation or for imports will be severely restricted when it comes to long term outages (weeks and months). Given Hydro One's station focused approach, it relies on fewer but longer outage periods. Any work at load stations that require outages affecting any element on the path needed to transfer Ontario generation or imports will be impacted. The analogy, as discussed by Mr. Ng is that it is equivalent to taking a Vacuum Building Outage (VBO) for 8 years

39 Transcript Volume 5, Pages 98-101.

40 Transcript Volume 1, Page 104.

41 Transcript Volume 5, Pages 156-160.

42 Staff Submissions, Table 3.

between 2022 and 2030.[43] In practice and based on past experience, when there is a 6 week VBO, outages in many parts of the system are restricted and not just at the nuclear site conducting the VBO.

54. Given the significance of the nuclear unavailability, which will affect the entire transmission system, Hydro One must take the prudent approach on the potential impacts to its work program until such time as additional information becomes available.

55. In sum, while Hydro One is not in control of refurbishment timing, Hydro One can control the timing and pacing of its investment programs. What Hydro One knows is that if it waits to conduct those necessary investments and investments are deferred to a time period closer to or overlapping with nuclear refurbishment, execution risk is heightened; system flexibility is lost; consequences of failures are increased; and greater challenges are imposed on the pacing of new work and assets that need remediation in those future periods.

Some specific projects have not involved IESO or the regional planning process and have not been demonstrated to meet future needs in the proposed regions/areas

56. The Regional Planning process is intended to identify needs and solutions to address those needs that required broader coordination between the transmitter, distributors and the IESO. The process is described in the "Planning Process Working Group Report to the Board – The Process for Regional Infrastructure Planning in Ontario", dated May 17, 2013 (and more specifically Appendix 1 where the Regional Infrastructure Planning process is described in detail. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf). The process also recognizes that there are many situations where needs can be addressed more appropriately and efficiently at a local level between a transmitter and a distributor and that broader regional planning coordination is not required.

57. Transmitters and distributors are responsible for bringing forth needs and issues that can benefit from broader regional planning coordination in the context of addressing regional needs. This can also include select sustainment investments that may impact regional planning. In the case of like-for-like sustainment investments, the vast majority do not

[43] Transcript Volume 7, Page 51.

require further regional planning coordination as there are no new regional needs involved and the only need is to sustain the existing facilities. Having said this, there are numerous situations where Hydro One has identified sustainment investments for consideration and coordination with the Regional Planning process.[44]

58. Regarding Staff's question on Dufferin TS, Mr. Young indicated,[45] that this discussion would not occur at the Regional Planning level as the request for increasing the transformer capacity coinciding with the end-of-life replacement would be appropriately conducted between the transmitter and distributor. The incremental cost of increased capacity will be borne by Toronto Hydro.

59. Regarding Staff question on the Hamilton area projects, discussions took place with the IESO and it was identified that only two projects, Gage TS and Kenilworth TS, needed further coordinated regional planning review with the distributors and the IESO, as part of the Burlington to Nanticoke Regional Infrastructure Plan which is currently in progress. This was explained in Hydro One's Response to OEB Pre-Hearing Undertaking #2.[46]

Integrated station investment approach has not been demonstrated. The rise in station expenditures could indicate unnecessary work is proposed

60. Staff's final assertion relates to scepticism directed at the value of the integrated station investment approach. The inherent value and benefit of the integrated station investment approach has been demonstrated: capital cost reductions totalling $57 million and $2 million in reduced OM&A costs. These avoided costs represent real savings to ratepayers. The approach taken by Hydro One in calculating these amounts was tested by Staff during the interrogatory process.[47]

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44 The table at Appendix "A" to these reply submissions summarizes the sustainment investments that have been referenced in the Regional Planning Exhibit B1, Tab 2, Schedule 3. As can be seen, while there are quite a number of sustainment investments referenced below, the selection referenced below remains a small number relative to all of Hydro One's sustainment investments because as noted, the majority of sustainment investments do not need Regional Planning coordination nor would it be effective to subject the majority of sustainment investments to Regional Planning coordination.

45 Transcript Volume 6, Page 27.

46 Exhibit K4.2.

47 Exhibit I, Tab 1, Schedule 62; Exhibit I, Tab 1, Schedule 64; Exhibit I, Tab 1, Schedule 65; and Exhibit I, Tab 1, Schedule 66.

61. Staff's questions during the oral hearing touched briefly on this topic. Ms. Lea's questions addressed the issue of whether work proposed was in fact necessary or not. Mr. Ng clearly refuted this latter suggestion.[48]

> MS. LEA: So does this mean that if you were not taking this approach, your station investments would be $57 million higher?
>
> MR. NG: That would be accurate.
>
> MS. LEA: Does it not mean also, though, that you do some work that you would not necessarily
>
> MR. NG: Excuse me, to qualify the answer --
>
> MS. LEA: Yes.
>
> MR. NG: -- that $50 million additional cost would be accurate if we were to continue on an asset-by-asset replacement basis.
>
> MS. LEA: But using the integrated station approach, does that not mean in some cases that you are doing work on assets, possibly replacing them, that would not be identified otherwise and are only being done because you are using this approach?
>
> MR. NG: *No, that's not correct*.
>
> The integrated investment, the idea there is we would go to our stations and we would look at, within three years' period of time, plus/minus three years, what do we need to do at that stations. We would be selecting asset that is at end of life or near end of life and bundle it together as one investment. One example would be if we are going there to look at a breaker, next to the breaker there will be two switches. The idea is when the breaker is at end of life you will look at the switches. If they are also at end of life or near end of life you would package it together and say, let's do it in one shot, rather than replace the breaker this year, come back a year later, and do the switches. That's the idea.

62. Ms. Lea went on to discuss with Mr. Ng, the nature of the three year window for near end of life assets, and referenced the fact that the length of this period was one year beyond the test year. Mr. Ng's response was clear citing Hydro One's evidence found in Exhibit B1-3-2. The three year time period has everything to do with asset condition assessments and the time required to carry out the investment activities. The reason for identifying end of life assets that arise within a three year window is that this time period aligns with the typical 3 to 5 year project execution duration required for scope development, design, construction and commissioning of integrated investment projects. Assets that are not in need of replacement or refurbishment are maintained until the next

48 Transcript Volume 6, Pages 2-13.

investment cycle when they are reassessed.[49] The inference of "unnecessary work" is mistaken and perhaps based on a belief that completion of all work (i.e., design through to commissioning) for identified integrated station investments occurs within the test years. That is not the case.

63. The three to 5-year planning and execution period may also be seen in the Investment Summary Documents,[50] as it is common for station programs to be developed over a longer time horizon. The three year window for near end of life assets is intended for the purpose of what Mr. Ng described as a "push pull" approach to ensure the size of the investment and the work that gets carried out under an integrated approach occurs in a rational manner and using professional judgment by individuals who are in charge of and have first-hand experience with managing the assets.

64. In Hydro One's submission, there is no evidence on the record to support Staff's inference that "unnecessary work" will be carried out under the incremental station project approach. On the contrary, the evidence is that the number one reason for integrated approach is to improve capital work execution efficiency.[51] The approach results in a reduction in outage requirements which reduces the impact on the customer, and also allows Hydro One to take a more complete, holistic look at what needs to be done at a given station to improve operational efficiency, such as consideration of whether a station with two transformers can be reduced to using only one transformer.[52]

iii) Other Asset Investments

Wood Poles

65. SEC and AMPCO note that 3% of Hydro One's wood pole population is now high risk as compared to Hydro One's previous rates application at which time 9% of Hydro One's

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49 Exhibit B1, Tab 3, Schedule 2, Page 5.

50 For example, see: Exhibit B1, Tab 3, Schedule 11, Attachment 1 at S01, S02, S03,S04, S05, S06, S07, S08, S09, S10, S11, S12, S13, S15, S16, and S17. All of these programs are multi year. Costs shown on the last page of each ISD and for each Test Year do not equal the "Total" because amounts were incurred in prior years or are expected to be incurred in future years.

51 Transcript Volume 6, Pages 3-7.

52 Transcript Volume 6, Pages 3-7.

wood pole population was high risk. For this reason, SEC and AMPCO submit that Hydro One should slow down the rate at which it is replacing high risk wooden poles.[53]

66. In response, Hydro One submits that the proposed level of wood pole replacement investments is needed to continue to focus on the replacement of Gulfport structures which are known to be defective. The improvements in performance of wood poles with regard to outage frequency and duration are improvements that have been achieved in part because of Hydro One's success in replacing Gulfport structures. AMPCO agrees with this conclusion, noting that it "believes that the reduced failure rates over time are in part due to the replacement of defective Gulfport structures on the system."[54]

67. Moreover, the majority of transmission wood pole structures are located in Northern Ontario and many of these structures support radial circuits.[55] Programs such as these address the communities and concerns that Anwaatin have raised.[56] A wood pole failure can often result in a direct customer outage.[57] In addition, given that approximately 6% of the wood pole population needs to be assessed to determine condition risk,[58] it is possible that the high risk wood pole population is higher than 3%.

68. Hydro One submits that there is no reason to reduce the rate of replacement of wood poles simply because the percentage of Hydro One's high risk wood pole population is now 3%. The more appropriate approach, Hydro One submits, is to maintain the current rate of replacement until Gulfport structures are completely changed out, assess the 6% of the wood pole population that has not been assessed which will inform overall wood pole population health, and then assess risk and reduce the replacement rate accordingly.

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53 SEC Submissions, Pages 42-43; AMPCO Submissions, Pages 22-23.
54 AMPCO Submissions, Page 22.
55 Exhibit B1, Tab 2, Schedule 6, Page 40, Lines 8-9.
56 Anwaatin Submissions at page 18.
57 Exhibit B1, Tab 2, Schedule 6, Page 40, Line 10; Exhibit B1, Tab 2, Schedule 6, Page 38, Lines 6-8.
58 Exhibit B1, Tab 2, Schedule 6, Page 42, Lines 17-18.

Protection Systems

69. Both SEC and AMPCO suggest that Hydro One's proposed level of protection system replacements should be reduced, given declines in forced outage frequency due to protection systems and stability in the condition of protection systems.[59]

70. However, SEC and AMPCO's submissions do not recognize that these types of investments are driven not only by the condition of the assets in question but also by matters of safety and technological obsolescence.[60] More specifically, old protection systems do not work well with new transformers or breakers and in some cases this can lead to mis-operation, reducing reliability, and underutilization of new desirable features that improve reliability, operational efficiency, and safety.[61] In addition, Programmable Auxiliary Logic Controller (PALC) relays, of which Hydro One still has approximately 400 in its system, have shown an increase in recorded defects and trouble calls; Hydro One plans to replace these over the next five years.[62] For these reasons, Hydro One submits that its proposed level of protection system replacements should be approved by the Board.

iv) Reliability

71. Staff and intervenors suggest that the Board consider Hydro One's proposals for sustainment expenditures in the context of its "generally good record of reliability", given Hydro One's top quartile ranking among its Canadian Electricity Association peers for reliability on its multi-circuit system.

72. However, Staff's submissions do not recognize how multiple circuit redundancy of the transmission system in southern Ontario has contributed to the CEA results.[63]

73. Staff appear to suggest that the CEA results support a view that proposed station work could be deferred to ease the cost impacts of the proposed stations investment on

59 SEC Submissions, Pages 40-41; AMPCO Submissions, Page 25.

60 Exhibit B1, Tab 2, Schedule 6, Page 28.

61 For example, Exhibit B1, Tab 3, Schedule 11, Investment Summary Document at S54, where a transformer second harmonics problem caused misoperation and is negatively affecting reliability.

62 Exhibit B1, Tab 2, Schedule 6, Page 26, Lines 11-16.

63 Staff does acknowledge that CEA statistics consider only the southern, multi-circuit portion of Hydro One's transmission system while the TADS metric considers the entire system, see Board Staff Submissions, Pages 19-21, but the issue here is that Staff is not properly taking into account the redundant characteristics of Hydro One's southern multi-circuit system.

customers. Proposed station work during the test years is declining. Reliance on CEA overall performance does not take into account Hydro One's concerns as stated in its evidence that equipment performance is a leading indicator of future system reliability; that by the time system reliability has measurably degraded, equipment performance will have deteriorated and a significant increase in asset level investment becomes necessary to return reliability levels to historical levels.[64]

74. Hydro One's transmission station equipment failures as compared to CEA statistics has demonstrated an upward trend of late, one which has exceeded the CEA 5 year moving average.[65]

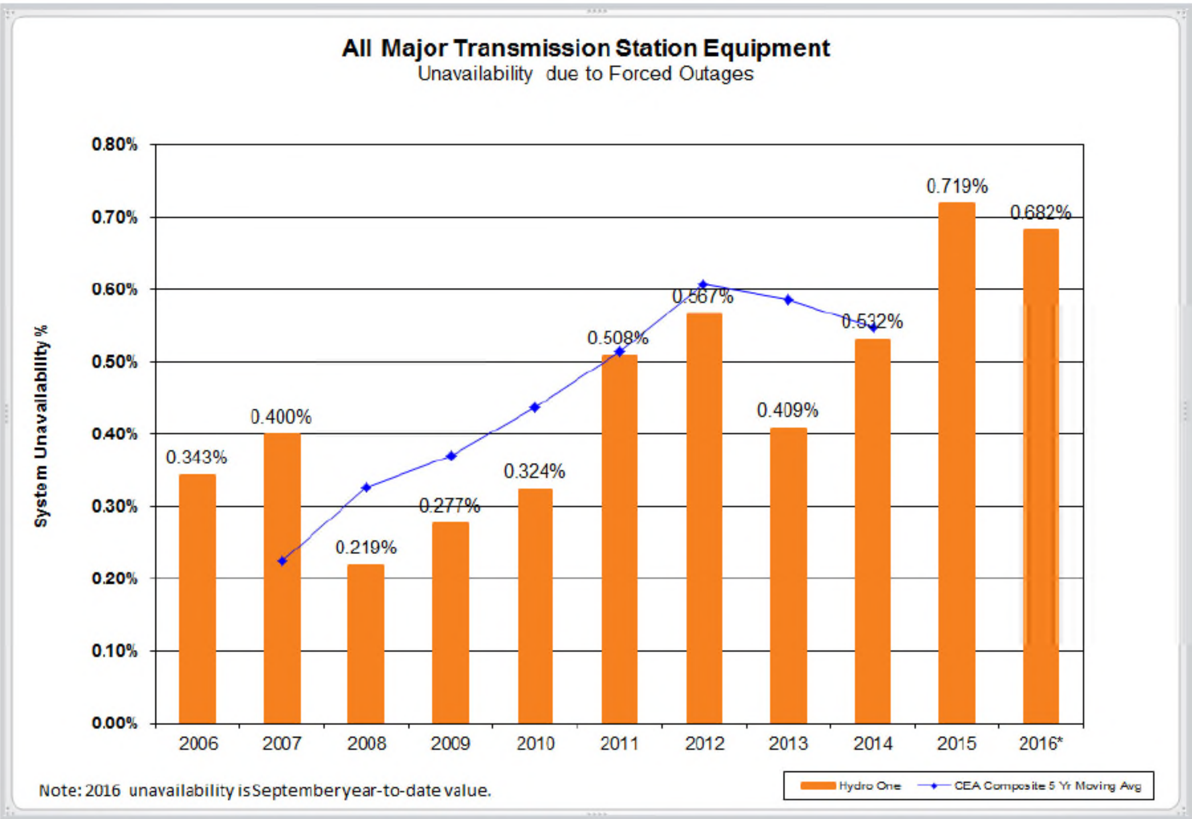


Figure 13: Unavailability of Major Transmission Station Equipment

75. In cross-examination with Mr. Brett, Mr. Penstone explained why system redundancy has shielded Hydro One from lower CEA performance.

64 Exhibit B1, Tab 1, Schedule 3, Page 27.

65 Exhibit J1.4.

> MR. PENSTONE: This goes to the thesis of the application that our assets are deteriorating and as a result of that deterioration, they are being forced out of service on a more frequent level. What you don't see is a commensurate degradation in reliability. So even though this equipment is being forced out of service at an increasing rate, it hasn't been manifest directly in terms of reliability performance. One of the reasons for that is because there is inherent redundancy. So a piece of equipment can be taken out of service, but because there is a second piece of equipment that can continue to serve customers, reliability has not changed. However, the reliability risk has.
>
> …
>
> MR. PENSTONE: Our assessments have been that the required pacing of investments – well, I will step back and say if you look at our assets today, most of them were built 50 or 60 years ago, and there was a considerable number of stations and assets that were built at that time. This was in the period where the province was growing at a positive rate, and the electricity infrastructure was being constructed to accommodate that growth, and there was a lot of infrastructure built at that time. So what we have been doing is basically replacing that infrastructure as it's reaching its end of life. And there is more. If you are just looking at the demographics of our assets, we actually have to continue the pace that we have been at over the last two years in order to address the continued aging of those assets.

76. Concerns respecting reliability were noted in the conclusions found in the Ontario Auditor General's Report[66]. Between 2010 and 2014 transmission system reliability deteriorated. Outages lasted 30% longer and occurred 24% more frequently. While Hydro One's overall transmission system reliability compares favourably to other Canadian electricity transmitters, it has worsened in comparison to US transmitters.

77. When redundancy is provided in parts of the system, the design intention is to establish an operational performance level that allows uninterrupted supply when there is a forced outage to a transmission asset. It is not intended to delay the replacement of assets until the asset fails. Doing so would compromise the performance intended and introduce further risks to other assets across the system. For example, breakers and transformers can fail explosively; when that occurs there is a risk of damage to adjacent or nearby assets. Subsequent failures can have an adverse impact to the system and connected customers. The redundancy design in Ontario and other transmission jurisdictions is premised on replacing assets when the asset conditions warrant it. That is how redundancy is maintained and so it can continue in the future. This is a critical and integral element of transmission systems designed to serve large load centres such as those found in southern Ontario. Thus, for Staff to suggest that Hydro One's CEA

[66] Auditor General's Report, Page 248.

reliability is an adequate basis on which to justify reductions to station sustainment investments, means that station asset conditions are not as Hydro One says; that end of life conditions have not been reached and thus investment levels are not necessary. This is not what the evidentiary record shows and is contrary to the OEB's focus on condition as a driver of asset replacement.

78. In addition to the CEA measures, evidence was filed in this proceeding relating to how Hydro One's reliability has fared against 21 peers involved in the North American Transmission Forum (NATF). The NATF information was provided in accordance with directions from the Board arising from Procedural Order No. 5.[67]

79. NATF's results show a sharp contrast to the CEA data: NATF's "Integrated Performance Indicator Index", placed Hydro One in the third quartile for 2015. Hydro One had only two 1st quartile placements in two IPII Sub-Categories, Human Error Element and Failed Protection System Element. Two 4th quartile rankings were issued for "AC Circuit Equipment per Hundred Miles" and "AC Circuit Unavailability per Element Per Year". The quartile and individual scores out of 21 are repeated below:

	Quartile			
	2012	2013	2014	2015
Number of Participants (including Hydro One)	21	21	21	21
IPII Total Score	3	3	2	3
IPII Score Failed AC Circuit Equipment per Hundred Miles	3	3	3	4
IPII Score Failed AC Substation Equipment per Element	2	1	1	2
IPII Score Failed Protection System per Element	4	3	3	1
IPII Score Human Error per Element	3	2	1	1
IPII Score AC Circuit Unavailability per Element per Year	3	3	2	4
IPII Score AC Transformers Unavailability per Element per Year	2	2	3	3
IPII Score Unknowns per Hundred Miles	2	2	2	2
IPII Score Lightning per Hundred Miles	4	3	3	3
IPII Score Weather Excluding Lightning per Hundred Miles	2	2	2	2
IPII Score Aggregate Residual Causes per Hundred Miles	4	3	3	3

67 See Exhibit K2.1, Pages 36-37 and the compliance filing dated November 23, 2016, filed on RESS in the EB-2016-0160 web drawer as "HONI_LETTER_re_NATF_Reliability_Report_Ranking_20161123".

	2012	2013	2014	2015
Number of Participants (including Hydro One)	21	21	21	21
IPII Total Score	15	13	8	13
IPII Score Failed AC Circuit Equipment per Hundred Miles	12	11	11	16
IPII Score Failed AC Substation Equipment per Element	8	2	1	7
IPII Score Failed Protection System per Element	16	15	15	1
IPII Score Human Error per Element	11	9	1	1
IPII Score AC Circuit Unavailability per Element per Year	15	15	9	16
IPII Score AC Transformers Unavailability per Element per	10	10	12	14
IPII Score Unknowns per Hundred Miles	9	10	10	8
IPII Score Lightning per Hundred Miles	19	13	15	12
IPII Score Weather Excluding Lightning per Hundred Miles	6	10	8	7
IPII Score Aggregate Residual Causes per Hundred Miles	19	14	15	14

80. Failed substation equipment per element dropped from the first to the second quartile between 2013 and 2015. Transformer unavailability per element per year has also declined and now rests in the third quartile ranking.

81. Traditional Reliability Metrics concerning lagging indicators of outage rates and durations normalized per circuit/element and circuit/mile for circuits 200-799kV were also provided in the NATF Information. Hydro One's best five year ranking was only 2nd Quartile. All other categories were 3rd and 4th Quartile rankings:

	Quartile			
	2012	**2013**	**2014**	**2015**
Number of Participants (including Hydro One)	21	21	21	21
AC Circuit Outage Rate per Hundred Miles per Year 200-799 kV	3	4	3	3
AC Circuit Outage Rate per Element per Year 200-799 kV	4	4	4	4
AC Circuit Average Outage Rate Duration of Sustained Outages 200-799 kV	2	3	2	2
AC Circuit Outage Rate Per Hundred Miles per Year-Momentary 200-799 kV	4	4	4	3
AC Circuit Outage Rate per Element per Year Rate-Momentary 200-799 kV	4	4	4	4
AC Circuit Outage Rate per Hundred Miles per Year-Sustained 200-799 kV	2	2	3	3
AC Circuit Outage Rate per Element per Year-Sustained 200-799 kV	3	3	4	4

	2012	2013	2014	2015
Number of Participants (including Hydro One)	21	21	21	21
AC Circuit Outage Rate per Hundred Miles per Year	15	16	15	14
AC Circuit Outage Rate per Element per Year	18	20	19	18
AC Circuit Average Outage Rate Duration of Sustained	9	11	10	10
AC Circuit Outage Rate Per Hundred Miles per Year-	18	18	17	15
AC Circuit Outage Rate per Element per Year Rate-Momentary	18	18	18	18
AC Circuit Outage Rate per Hundred Miles per Year-Sustained	9	10	11	11
AC Circuit Outage Rate per Element per Year-Sustained	12	14	17	16

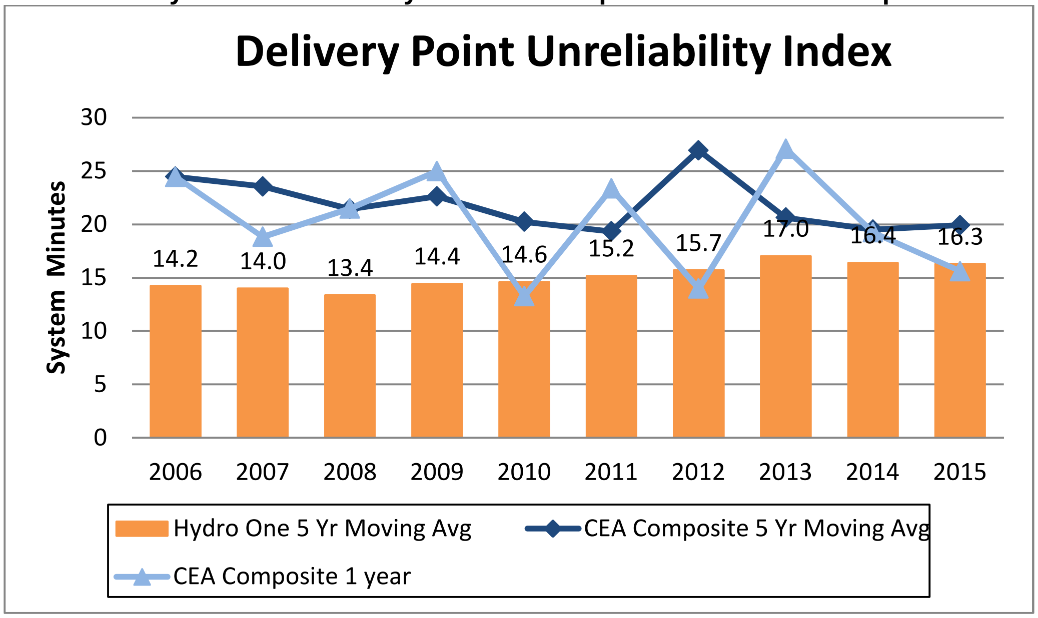
82. The consistent 4th Quartile ranking of AC Circuit Outage Rates per Element per Year for Momentary Outages is particularly relevant, as feedback from Hydro One's customer engagement process was that momentary outages can have the same devastating impacts as a sustained outage for major industrial transmission customers. The duration of an outage is not as relevant as it has been in the past.

83. Mr. Rubenstein and Mr. Penstone discussed the significantly different results in the reliability metrics between the CEA and NATF values. [68] The NATF information was not discredited by any other party during the hearing process. It is therefore unclear how Staff's preference for the CEA reliability data to the exclusion of the NATF data provides a sound basis for the suggestion that "actual reliability achieved through historical levels of spending suggests that the significant ramp up in sustainment spending is unnecessary and can be better paced."

84. VECC addresses reliability at pages 15-22 of its argument. VECC suggests that Exhibit J8.2 negates any assertion that Hydro One is suffering from deteriorating equipment performance, because performance is improving. Figure 11 found in this Exhibit is repeated below. The yellow bar chart represents Hydro One's five year moving average of system minute outages. Since 2010, the trend is flat or slight increases in system outage minutes (i.e., flat or declining reliability). So, while delivery point reliability has not increased, as shown in Figure 13 (see above paragraph 75), forced equipment outages are increasing and this is a leading indicator of future system reliability.

[68] Transcript Volume 1, Pages 70-72.

Figure 11: Comparison of the Hydro One Five Year Moving Average for the Delivery Point Unreliability Index as Compared to the CEA Composite



85. At page 17 of its argument, CME raised concerns that Hydro One had mischaracterized information provided in its customer presentation by presenting 10 years of SAIDI and SAIFI information; characterizing overall transportation reliability as having been flat over the past 10 years; and not highlighting that Hydro One's SAIDI transmission reliability metric had improved over the past 5 years.

86. Hydro One submits that the SAIDI/SAIFI information found in the customer presentation was accurate and not misleading. The customer presentation was presented to all transmission customers, not just those that are on multiple circuit lines. The information was comprehensive and not tailored to specific sets of customers, such as multi circuit versus single circuit customers. Ten year reliability performance information has historically been provided by Hydro One in past rate filing exhibits on reliability performance. Hydro One saw no reason to depart from that approach.

87. Finally, CME disregards the fact that information explaining differences between multiple circuit and single circuit performance was presented elsewhere in the customer presentation (see slides 11 and 12 of Exhibit B1-2-2-2). Customer discussions included the 10 year historical unplanned outage hours data.[69] Positive feedback was received

[69] See Customer Consultation Report produced by IPSOS, page 22, "System Performance".

regarding this information and the explanations given. Customers stated that they understood what network performance was, and what subsystem multi and single circuits were. Some customers also remarked that historical analysis regarding reliability performance was best considered as a trend rather than spot metrics.

88. Based on the foregoing, Hydro One submits that reliability information presented to customers was presented fairly and accurately.

b) Planning

i) Planning evidence

89. Staff and intervenors assert that Hydro One's planning evidence was not clear enough. However, Staff's submission provides an accurate and succinct summary of how Hydro One's planning process works.[70] Three areas of concern were cited:

- As compared to oral hearing testimony, Hydro One's pre-filed TSP evidence did not provide a clear picture of the planning process or reasons behind asset selection, specifically:
    - Lines asset condition evidence should have received greater attention and focus in the TSP and described as the main, if not the sole reason for the projects; and
    - Investment Summary Documents and Business Cases were inconsistent.
- There was "some evidence" that Hydro One's "actual planning" was inadequate which may indicate "some fault in the planning process at the company"; and
- Additional reporting on prior approved projects and programs should be included in subsequent revenue requirements applications.

By undertaking a detailed review of its evidence, Hydro One will demonstrate below that Staff's assessment is not reasonable.

70 Staff Submissions, Page 3.

<u>Was the Lines Investment Asset Condition Justification Unclear, Inadequate, or Incomplete in the Pre-filed Evidence?</u>

90. Hydro One's pre-filed TSP Evidence consistently cites and explains the importance of asset condition as the main reason for individual capital investments. In Exhibit A-3-1 Page 11 Lines 8-33, Hydro One explained its concern regarding asset condition deficiencies. In Exhibit A-9-1 Attachment 1, which was the Customer Power Point slide presentation provided to customers in April 2016 (i.e., before the Application was filed) Hydro One went to great lengths to explain "the transmission system faces increasing challenges due to asset condition" and "condition assessments have identified critical replacement needs." In Exhibit A-10-1 Page 1, Hydro One's proposed Draft Issues List for this proceeding, asset condition was stated as one of the key factors addressing whether the proposed capital investments were appropriate (Issue 5). Similarly, Issue 10 addressed asset condition in the context of whether OM&A expenditures were appropriate. These express references to "asset condition" make it clear that the asset condition evidence was in fact highlighted before and at the outset of the Application.

91. The TSP was introduced in Exhibit B1-1-1 and asset condition was a primary focus of this evidence. The narrative explained that central to Hydro One's Investment Planning Process was the identification of asset needs and asset management approaches. Three separate exhibits set out the planning process used to identify asset needs:

- Exhibit B1-2-4 addressed Hydro One's approach to asset management. Page 1 of this Exhibit explained that the Investment Process "begins with a review of the system with a focus on reliability performance, reliability risk, asset demographics and asset condition information."
- Exhibit B1-2-5 addressed asset specific assessments, and goes to some lengths to explain how individual asset needs are determined using an asset risk assessment process that relies on asset condition, engineering analysis and the input of experienced planning professionals.
- Exhibit B1-2-6 provided a 66 page discussion on specific asset classes that were identified as requiring investment due to asset condition. This included a discussion of conductors and testing. The summaries provided an overview to the criteria used to assess the fleet assets, including demographics, condition assessment, performance and other relevant factors that lead to asset replacement decisions.

- Exhibit B1-3-2 provided a 44 page discussion of the Sustaining Capital Investment Program. At page 30 of this exhibit, lines investments were discussed. Conductor testing was described and a Table of the specific Transmission Lines Refurbishment Projects was provided based on that testing program.[71] Investment Summary Documents also provided additional information about individual asset justifications.[72]

92. With respect to insulator condition assessments as the principal justification of planned investment during the test years, the pre-filed Application and interrogatory evidence made appropriate references to asset condition, specifically:

- The April 2016 Customer Presentation identified that approximately 25% of the insulator population was at a "greater risk of failure" and that "ongoing testing will determine remaining insulator strength".[73] The presentation further referenced that "Insulators installed between 1965 and 1982 have a known increased risk of failure. The Etobicoke incident was specifically referenced; as was the fact that condition testing was underway to better quantify the increased risk.[74] This information was disseminated to customers before the Application was filed.
- In Exhibit B1-2-6 commencing at page 54, Hydro One presented evidence of its Transmission Lines Insulator Investments. Reference was made to the defect found with the Canadian Ohio Brass and Canadian Porcelain ("COB/CP") insulator and an explanation was given as to how the defect can result in two possible failure modes: (1) mechanical failure leading to line drops; or (2) electrical failures that result in reductions to insulating properties. The evidence went on to explain that a significant public safety risk arose as a result of the V76R line drop in Etobicoke in March 2015. The significance of this event was carefully considered by Hydro One. Hydro One carried out investigations and implemented a replacement strategy.[75] The asset strategy adopted was explained in the clearest of terms: address those insulators found in public areas, given the potential impact on public safety. It will take four

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71 Exhibit B1, Tab 3, Schedule 2, Pages 32-33, Table 15.

72 Exhibit B1, Tab 3, Schedule 11, Attachment 1, Investment Summary Document at S63, S64, S66, S67, S68, S69, S70, S71, S73 and S7.4.

73 Exhibit A, Tab 9, Schedule 1, Attachment 1, at Presentation, Page 8.

74 Exhibit A, Tab 9, Schedule 1, Attachment 1, at Presentation, Page 22.

75 Exhibit B1, Tab 2, Schedule 6, Page 56.

years to address targeted insulators by adopting this strategy.[76] In the Sustaining Capital Investment sections of the Application, repeated references were made to the need and justification for the insulator replacement investments.[77]

93. Discovery processes in advance of the oral hearing also provided effective ways to understand Hydro One's Application evidence, particularly on the matter of how asset condition as a factor was used in the planning process.

94. For example, consider Staff's several interrogatories on this topic. In Exhibit I-1-22(d) Hydro One explained that its "conductor fleet management approach is to replace aged and deteriorated conductors, verified by actual laboratory test results, to ensure safety and maintain reliability." In part (g) of this Interrogatory, Staff specifically asked whether "the actual list of conductors being proposed for replacement comprises the oldest conductors, and if not, please identify how the actual list was developed." Hydro One's answer was responsive and expressly referred to conductor samples validated through third party laboratory testing. The laboratory verification process for conductors was consistently discussed throughout Interrogatory Responses.[78] Sample reports were

[76] Exhibit B1, Tab 2, Schedule 6, Page 57.

[77] Exhibit B1, Tab 3, Schedule 2, Pages 3-4 and 38; Exhibit B1, Tab 2, Schedule 6, Pages 54-59; Exhibit B1, Tab 3, Schedule 11 at S76 and S79.

[78] Exhibit I, Tab 1, Schedule 22(f): "In practice, conductor replacement candidates are chosen based on laboratory verification of asset condition. Although there is a high degree of correlation between conductor age and condition, not all chosen replacement candidates are the oldest conductors."

See Exhibit I, Tab 22(g): "The proposed conductor replacement candidates described in Investment Summary Document S63, S64, S66, S67, S68, S69, S70, S71, S73 and S74, are based on actual conductor samples removed from the respective lines and end of life condition validated via laboratory testing."

See Exhibit I, Tab 1, Schedule 51: "Exhibit B1-2-4, Figure 5 shows the potential conductor replacement needs based on age demographics and average life expectancy for conductors. Hydro One proposed conductor replacement plans are based on confirmed laboratory condition tests, on those circuits that have been assess, as Hydro One does not replace conductors based on age only. Figure 24 in Exhibit B1, Tab 2 Schedule 6 provides information regarding condition assessment for conductors."

See Exhibit I, Tab 1, Schedule 70 which describes the Lines capital spending for 2017 and 2018 and the reasons for the significant increases. As it relates to Conductors: "Hydro One's transmission lines refurbishment program is driven by condition of the conductor(s). All conductors on selected circuits for refurbishment have been assessed through laboratory tests. Those selected for 2017 and 2018 refurbishment programs are confirmed to be at end of life, with low remaining strength or low torsional ductility, increasing the probability of catastrophic line drop incidents. <u>*Given the confirmed condition of the assets and associated safety and reliability risks, Hydro One does not have flexibility in timing of these projects*</u> [emphasis added]."

Conductor testing was similarly described in other Interrogatory Responses. See: Exhibit I, Tab 2, Schedule 39; Exhibit I, Tab 9, Schedule 6 Attachment 4 (Electricity Power Research Institute Report "Evaluation of Hydro One Conductor Assessment Program dated July 2016) and Attachment 5 (sample independent laboratory Report, prepared by Kinectrics Inc. entitled "Estimate of Remaining Life of Conductors on Circuit D2L").

provided in response to the independent laboratory verifications that took place and in response to interrogatories.[79]

95. Another example is Hydro One's response to BOMA 39 (Exhibit I-9-39) as it concerned the relationship between managing reliability risk through increased investments:

> Hydro One's proposed capital expenditures are based on investment needs as described in Exhibit B1, Tab 2, Schedule 5. The majority of these investments are required to replace end of life assets, which have been verified via condition or performance assessment, or laboratory testing, to maintain reliability. In addition, the chosen investments include assets that are deemed to be most impactive to system reliability. Therefore, replacing these deteriorated assets will reduce reliability risk. Details of these investments can be found in Exhibit B1, Tab 3, Schedule 2.

96. Multiple interrogatories were also asked with respect to the proposed insulator lines investments.[80] The answers provided were responsive, as Hydro One made it clear to Staff that "given the confirmed condition of the assets and associated safety and reliability risks, Hydro One does not have flexibility in timing of these projects"[81] and that the increases in investment in the test years are the result of new information relating to insulator asset condition validated by a testing program commenced in 2016 by EPRI.

97. While disclosure of the EPRI Report did not occur prior to the interrogatory process and only after completion of the Technical Conference, no party asked any questions about its contents or challenged its methodology, or its conclusions. Given this, it is difficult to see how Hydro One's pre-filed insulator asset condition evidence can reasonably be characterized as unclear, inconsistent or incomplete.

98. During the Technical Conference, opportunity was provided to Staff to follow up on and seek clarification of Hydro One's Application and interrogatory responses. In its letter dated September 19, 2016 Staff indicated up front that they intended to do so, and specifically with regard to the Transmission System Plan.[82]

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79 Exhibit I, Tab 9, Schedule 6, Attachments 4 and 5.

80 See Exhibit I, Tab 1, Schedule 55; Exhibit I, Tab 1, Schedule 62(a)(i); Exhibit I, Tab 1, Schedule 70; Exhibit I, Tab 2, Schedule 43(f); Exhibit I, Tab 1, Schedule 106(2); Exhibit I, Tab 3, Schedule 4; Exhibit I, Tab 3, Schedule 33; Exhibit I, Tab 3, Schedule 35; Exhibit I, Tab 7, Schedule 5; Exhibit I, Tab 9, Schedule 6.

81 Exhibit I, Tab 1, Schedule 70, Page 2.

82 OEB Staff Letter dated September 19, 2016, re: "OEB Staff Technical Conference List of Topic Areas for Questioning".

99. As it relates to Hydro One's Planning Process and its pre-filed Evidence, Mr. Penstone provided a specific presentation on this topic.[83] The presentation was based on and followed the pre-filed Application in order to be consistent and coherent. Despite the complex, technical nature of the Hydro One Planning Process, Mr. Penstone's presentation was appreciated by intervenors, as demonstrated by Mr. Rubenstein's remarks during the Technical Conference that Mr. Penstone's presentation and follow-up answers on at least some questions were "very helpful'.[84]

100. In its argument, Staff do not explain how the pre-filed Application evidence on the Planning Process, the interrogatory responses, Mr. Penstone's technical conference presentation, or the follow-up questions and the many undertakings that followed from that process were lacking and therefore not clear and coherent.

101. During the Technical Conference, parties asked questions regarding the conductor investments. The answers provided were consistent with the pre-filed evidence. No party asked any follow-up questions regarding the content of the Kinetics Inc. conductor laboratory testing sampling report that Hydro One provided in its Interrogatory Response to CME 9, indicating that Hydro One's stated reliance on and justification for the need for conductor replacement investment – as set out in its pre-filed Application and evidence was accurate, provided a consistent "picture", and was justified and complete. If it were otherwise, parties would have asked questions or tested this evidence. Intervenors and Staff did not challenge the report at the Technical Conference and nor did they do so during the oral hearing.[85]

102. With respect to the insulator lines Investment, follow up questioning on the reason for this program, including questions as to why the program was not executed sooner, occurred during the Technical Conference.[86] Mr. Penstone described the nature of the new information emanating from the Etobicoke line drop. The answers provided to Staff's consultant, Mr. Oakley, were entirely consistent with the information found in the Application, and in the Interrogatory Responses.[87] Indeed Mr. Oakley noted that Mr.

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83 Technical Conference Transcript Volume 1, Pages 123-127.

84 Technical Conference Transcript Volume 1, Page 130.

85 Based on a review of the transcripts no party asked any questions regarding Exhibit I, Tab 9, Schedule 6, Attachments 4 or 5. Mr. Penstone, however, referred to this evidence during Direct Evidence (Transcript Volume 5, Page 14).

86 Technical Conference Transcript Volume 1, Pages 128-130, 139-141 and 171.

87 Technical Conference Transcript Volume 2, Pages 39-41.

Penstone's explanations were "helpful".[88] Mr. Ng also provided responses to Mr. Oakley's questions regarding the nature of the insulator defect as well as the timing of the planning measures taken as explaining why there was a ramp up in investment amounts as compared to prior years,[89] consistent with the pre-filed evidence.

103. Questions seeking clarification on how Hydro One carries out its planning process and the nature of the segmented steps were limited and addressed in seven pages of Technical Conference transcript.[90] Staff did not indicate that they were confused by the evidence or responses given, or that the Application evidence or Interrogatory Responses were inaccurate or incomplete. In fact, what Mr. Oakley said about the transmission planning process as it related to individual projects was that he appreciated asset investment decisions were not based purely on the results of the asset analytics tool, that he understood the process was more complex than that and it requires judgment at several stages outside of the asset analytics assessment.[91]

104. Staff was provided further clarification on station reconfiguration investments. Station reconfiguration opportunities only arise when Hydro One has a "going in" end of life or other asset performance reason to make investments at the station. When that happens, only then is consideration given to whether other efficiency opportunities can be realized through reconfiguration design.[92]

105. Finally, the topics of insulator replacement justification and the tower coating program were addressed.[93] None of this discussion, again, casts doubt on the clarity, coherency and justification for the planned programs.

106. An objective review of the record in this proceeding demonstrates that Hydro One's justification for its lines investments did not change and was clear from the initial stage of the process to consider this Application. The evidence discussed during the oral hearing was found in the pre-filed evidence and discussed extensively during the Technical Conference.

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88 Technical Conference Transcript Volume 2, Page 41, Line 18.

89 Technical Conference Transcript Volume 2, Page 69.

90 Technical Conference Volume 2, Pages 58-64.

91 Technical Conference Volume 2, Pages 64-65.

92 Technical Conference Volume 2, Pages 65-68.

93 Technical Conference Volume 2, Pages 69-74.

Are Differences Between Investment Summary Documents and Business Case Summaries Valid Reasons to Support Staff's Criticism of the Pre-filed Evidence?

107. Staff's criticism appears to be based on the incorrect belief that Investment Summary Documents ("ISDs") and Business Case Summaries ("BCS") are prepared for the same purpose and therefore the content found in each should be identical. As was explained both before and during the oral hearing, this is not the case.

108. ISDs are prepared for a specific purpose: to provide a summary description of capital investment projects (greater than $3 million) and programs (greater than $3 million) whose costs (in whole or in part) form part of a Hydro One revenue requirements application. The form of the ISD filed in this Application is one that has consistently been used by Hydro One in the past for both its transmission and distribution applications. In the case of transmission, ISDs have been included in rates applications dating back to 2005.[94] The ISDs are designed for and used solely in regulatory applications.

109. BCS documents serve Hydro One's internal management planning and funding approval processes. They are prepared specifically for the purpose of authorizing expenditures and releasing funds for projects. BCS are prepared at the end of the planning process – when much greater information is available to properly assess budgetary and project timing needs.

110. Mr. Penstone clearly explained these differences during the Technical Conference. He did so in his initial presentation when he explained that business case summaries have a very specific purpose and are carried out at the end of the planning process – during the fifth box, as he put it, in reference both to the presentation slide deck and the Application evidence. In his conversation with Mr. Oakley, Mr. Penstone explained that BCS' require more detailed and accurate cost estimates than the information that is available at the time Investment Summary Documents are prepared,[95] that is, information that only exists immediately prior to work execution:

> So the fifth box refers to the actual release or commitment of individual projects. So for our large station integrated station investment, before we commit that

[94] See EB-2014-0140, Exhibit D2, Tab 2, Schedule 3; EB-2012-0031, Exhibit D2, Tab 2, Schedule 3; EB-2010-0002, Exhibit D2, Tab 1, Schedule 1 and Exhibit D2, Tab 2, Schedule 3, Page 1, for the 2007-2008 test years.

[95] Technical Conference Transcript Volume 2, Pages 57-59.

> project, we would have estimates developed. We are now undertaking more activity to come up with a more accurate estimate.
>
> It's not only in terms of additional engineering, but also additional examinations in terms of how the project will also be executed. And when I say how a project will be executed, it goes back to what are the various stages that will be required and for each stage, what are the necessary outages that will be required to enable the work to be undertaken. And we want to make sure that those outages are manageable and we'll be able to get the necessary approvals, so they don't have either an adverse impact on customers or the reliability of the bulk power system.[96]

111. The criticism levied by Staff with respect to asset analytics scores not appearing on the investment summary document, does not mean that Hydro One does not take or use asset analytic results in its planning process. Mr. Penstone indicated during the Technical Conference to Mr. Oakley that investments are not made purely as a result of asset analytics scores. Mr. Oakley said he appreciated that; he understood the process was more complex than that; and it requires judgment and other factors at several stages.

112. It is clear from the record that differences between ISDs and BCS' have been explained and that these differences are justified given the different purposes involved. Information contained for all project and program BCS' is not available when rates applications are filed. ISDs therefore serve a valid purpose to meet this need. As a result, Hydro One does not support either of Staff's recommendations.

ii) Planning Process

113. A number of interveners raised issues with Hydro One's planning process. These issues are addressed in turn below.

<u>*Increase in capital spending from levels originally forecast for the test years in previous application*</u>

114. Staff and other parties noted that the current level of proposed investment is greater than levels forecast for the same years and found in previous applications. However, no explanation was provided as to why it is a reasonable assumption that a forecast prepared in conjunction with a previous application for rates revenue requirement should or would be as accurate or better than a more current forecast for the same test years.

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[96] Technical Conference Transcript Volume 2, Page 59.

115. Hydro One provided detailed evidence as to the circumstances giving rise to the changes in forecast capital investment. New information and technology came to light with respect to tower coating. Conductor laboratory testing was carried out. The need for a more robust insulator replacement programs was identified.[97] New information was obtained relating to customer needs and preferences through the IPSOS Engagement process. Additional experience with integrated station investments was gained. [98]

116. The timing and delivery of new information explains the difference in the cited forecast variance. Mr. Ng explained that most of the conductor assessment results were not received until after the EB-2014-0140 application had been filed.[99] Similarly the Etobicoke incident happened in March 2015. Technology and studies supporting the tower coating program were not known prior to the preparation of this Application. Information emanating from the IPSOS Engagement process and use of the reliability risk approach were specific to this Application.

117. It is an undisputable fact that planned sustainment investment has increased in this Application versus Hydro One's application in EB-2014-0140. Increases in planned capital investment do not, in and of itself, demonstrate inadequacy or fault with Hydro One's planning process. The evidence clearly demonstrates that Hydro One has received new information and has, using proper and robust planning processes and sound professional judgment, taken this information into account and provided new investment forecasts that reflect the objective condition assessments of the company's assets.

Defective Insulator Planning

118. Regarding the assertions made by Staff relating to the pacing of the insulator program, and assertions that Hydro One should have pursued legal remedies to extract compensation from defunct manufacturers, Hydro One submits neither suggestion has merit in demonstrating inadequate planning. As noted above, Mr. Ng explained that the performance of the COB/CP insulators was being monitored since the 1980s. Two failure mechanisms – line drops as well as reduced insulation properties – were known. Up until 2015, the number of line drops had not materially changed or resulted in any

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[97] Technical Conference Transcript Volume 2, Pages 40-41.

[98] Exhibit I, Tab 1, Schedule 106.

[99] Transcript Volume 7, Page 62.

major public safety concern. The 2015 Etobicoke incident prompted additional action and Hydro One's planners immediately took steps to address the issue in a careful, objective and timely manner, addressing risks to public safety and pacing the planned replacements to avoid rate consequences associated with premature asset replacement.

119. The fact that those prior periods did not see a ramp up in insulator investments begs the question as to what evidentiary basis would Staff expect Hydro One to have to support such a ramp up? Justification for rapid and extensive insulator investments did not exist. While manufacturing defects were known, forced outages from insulator failures were stable over the past 10 years.[100] The second failure mechanism, reduction in insulator properties, was being monitored. On average 200 circuit-structures of insulators were being replaced per year, the lion's share of which were manufactured by COB/CP.[101].

120. Regarding Staff's comments on legal remedies, Hydro One reminds the Board that the defects came to light in the 1980s – some 20 years after the porcelain insulator was manufactured. How and to what extent Ontario Hydro investigated its remedies as they may have existed at that time is not known. The notion that successful tortious actions could have been realized in that era, by an aggrieved party who had used a product successfully for over 20 years or more, would on some level appear to have a degree of legal uncertainty. Added to this, are Mr. Ng's observations, namely, that the companies involved went out of business.[102] Bankruptcy and insolvency laws afford judgment creditors little in the form of protection.[103]

121. In its argument Staff state that "proper pacing of capital investments does not mean ignoring or minimizing an identified need". Hydro One agrees. There is no basis, however, for the suggestion that needs have been ignored or minimized. What the evidentiary record reflects is that Hydro One's actual planning has responded appropriately, in a measured way that addresses what is now known: defective insulators can impact public safety. A four year program to address the potential consequences of insulators in high risk locations based on new condition information is appropriate and planned investments are properly paced.

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[100] Exhibit B1, Tab 2, Schedule 6, Page 57, Lines 13-15.

[101] Transcript Volume 8, Pages 61-62.

[102] Transcript Volume 8, Page 19.

[103] See *Bankruptcy and Insolvency Act*, RSC 1985, c B-3, s 178(1).

Problems identified in the Internal Audit Report had not been addressed prior to the filing of the Application.

122. Finally, Staff refer to conclusions found in Hydro One's Internal Auditor Report concerning Investment Planning[104], and claim outstanding recommendations "may" provide a basis to support a view that there may be an issue with Hydro One's planning process. This assertion is inconsistent with the evidence filed in this proceeding relating to Hydro One's planning process, asset condition evidence, and reflects a misunderstanding of the purpose of internal audit documents.

123. The Internal Audit function is a critical tool used as part of the governance and enterprise risk management function of a corporation, providing oversight and feedback on organizational processes. Internal audit reports can also be used to promote efficiencies and continuous improvement; however this is not the primary purpose of the Internal Audit function. Hydro One is concerned with Staff's position that conclusions found in internally prepared audit reports of company activities should have real and substantial bearing on decisions that establish Hydro One Transmission's revenue requirement. If Staff's views are accepted by the Board, the future reliance and value of the internal audit function is likely to change dramatically as utilities will be wary of the misuse of these reports and conclusions to justify revenue requirement reductions.

124. The fact that some recommendations from the Internal Auditor Report were outstanding prior to the filing of the Application does not show that Hydro One's planning process was inadequate or faulty. Exhibit K4.4 provides useful ways for Hydro One to improve. Hydro One is taking reasonable steps to achieve that outcome under the direction and increased sophistication of new senior management. However, none of these developments support the suggestion that the applied-for sustaining capital investment forecast is unreasonable. The fact Hydro One manages its continuous improvement objectives with the assistance of an Internal Audit function is positive. Good checks and balances make for efficient and effective work processes.

[104] Exhibit K4.4.

The Need for Additional Reporting

125. At page 18 of its submission Staff recommend that Hydro One should be required to report on the status of major projects or programs that were identified in the previous application. The purpose of this reporting is to demonstrate whether programs were completed, whether money was re-directed to a different project and the reasons for the change.

126. Hydro One makes two observations in reply. First, Staff's request is inconsistent with the Board's Filing Requirements for Electricity Transmission Applications.[105] The Filing Requirements are clear that the applicant must provide justification for changes from year to year to its rate base, capital expenditures, operations, maintenance and administration costs and other items above a materiality threshold.[106] However, an accounting of specific projects and programs is not required.

127. Second, obligating Hydro One to track individual projects and programs for and to assess changes in what was originally forecast versus what is filed in the next application changes the intended focus and nature of the decision approval process. As discussed by Mr. Quesnelle, transmitter revenue requirement approvals are intended to assess prospective forecasts of envelope spending levels and not the approval of spending on specific projects.[107] This level of assessment is appropriate because changes and to projects and programs are expected. Tracking these costs and changes in programs and expenditures at this level in order to provide an application by application comparison would have little value given the fundamental question is whether and why prospective forecasts of costs are just and reasonable.

128. For these reasons, Hydro One does not support Staff's proposal.

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[105] Ontario Energy Board Filing Requirements For Electricity Transmission Applications, dated February 11, 2016, Chapter 2 ("**OEB Filing Requirements**").

[106] OEB Filing Requirements, Chapter 2, Page 6.

[107] Transcript Volume 6, Pages 50-51.

Conclusion on Planning

129. The critical assessment of complex and technical evidence requires the use of precise and accurate statements. Hydro One believes that parties' views on accuracy, completeness and consistency are not well founded. The evidentiary record is clear, accurate and complete.

130. There is no dispute that the multiple processes that are used by Hydro One in its Planning Process are complex, in terms of development, execution and 3rd party understanding. Hydro One agrees with parties on this point and that the exercise at hand requires a system plan to be robust and comprehensive. However, it must be acknowledged that the task at hand involves a great number of technical elements.

131. Hydro One is attentive to the views expressed by interveners. It will give further consideration on ways it may improve understandings including application content and organization going forward.

c) Customer Engagement

i) Timing of Engagement

132. Staff and intervenors suggest that the IPSOS Engagement process was flawed because there was insufficient time between when information was received from the IPSOS Engagement process and when Hydro One finalized its TSP. Staff's remarks suggest potential misunderstanding of the IPSOS Engagement objectives and why it was appropriate for this process to be conducted in the time period it was.

133. As described in Hydro One's Argument In Chief, the IPSOS Engagement provided focused transmission customer engagement used in the development of Hydro One's TSP.[108] Customer feedback was received throughout the planning process. The IPSOS Engagement was an additional forum that provided significant feedback on its focused purpose: understanding customer views on three interrelated variables: needs and preference (or outcomes), transmission rates and capital investments. Timing concerns did not arise because Hydro One appropriately managed this initiative concurrently with the development of its application and the TSP. Conducting the IPSOS Engagement in

[108] Hydro One Argument In Chief, Pages 24-29.

proximity to the preparation and filing of the Application was appropriately managed and has not been reasonably shown to detract from the quality of the TSP evidence. Indeed, the IPSOS Engagement process provided valuable input; input that validated and shaped the content of the TSP.

ii) Selection of Participants

134. Staff's recommendation is that future transmission customer engagement activities elicit more information from LDC end-use customers regarding views and preferences regarding transmitter concerns. Hydro One agrees that ongoing consultation with its LDC transmission customers is essential. Affirmation that LDC's views are informed by its end-use customers is a reasonable approach and one which recognizes that transmission engagement activities should remain focused with informed transmission customers.

135. In response to Anwaatin's submissions regarding consultation with First Nations on this Application, Hydro One's views on this matter were addressed in its Argument-in-Chief.[109]

iii) Limited Scenarios

136. Staff suggest that because the IPSOS Engagement exercise did not formally present a "zero cost increase" scenario, customer feedback received regarding capital expenditure envelope, rate increase and reliability risk tolerance was weakened.

137. Mr. Penstone and Mr. McLachlan discussed "do nothing" and "zero cost" scenarios with Ms. Grice and Ms. Blanchard during the oral portion of the hearing.[110] The record explains why neither of these scenarios were reasonable alternatives. A "do nothing" hypothetical scenario would effectively strand and defer all multi year projects and programs already underway. A zero rate increase scenario, meaning maintaining capital expenditures at historic levels, was unacceptable because it would "stack" projects and programs that are required to be carried out in order to address deteriorated asset condition and is a scenario that Hydro One engineers and management could not support. That is understandable because the age of the fleet keeps increasing and it is

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[109] Hydro One Argument-in-Chief, Pages 33-35.

[110] Transcript Volume 2, Page 134; Transcript Volume 7, Pages 42-48.

reasonable to expect that remaining assets not considered in historical programs will continue to deteriorate.

138. Staff's criticism also suggests that transmission customers were not provided an adequate or sufficient opportunity to understand a zero cost scenario. However, the evidence shows that Hydro One addressed questions regarding a zero cost scenario.[111] Information in this regard was included in the Customer Consultation Report produced by IPSOS (the "IPSOS Report") and referred to by Mr. McLachlan during his conversation with Ms. Blanchard. The IPSOS Engagement did not restrict this type of questioning and feedback.

iv) Reliability Risk Model

139. 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, not used in the actual planning of its investments, and exaggerated capital benefits. Intervenors also raised issues with the model for "reliability risk".

140. The hypothetical scenarios used during the IPSOS Engagement were not based solely upon the reliability risk metric. The scenarios developed had three dimensions: capital investment, reliability risk and transmission rate impact. All of these elements were given equal consideration.[112]

141. The reliability risk model is a new tool. Hydro One created this as an additional and value added element of assessing outcomes of decisions made in a complex environment that has an over-abundance of lagging indicators that do not correlate in the same time period that investments are made. It is a risk communication tool conveying leading, instead of lagging, indicators of risk. The evidence was that sophisticated transmission customers understand this difference.[113] The utility of new tools improves with time; the predictive value of the leading indicators is expected to improve with experience and track record. Staff's assertions that the tool has no value because it (a) does not address "real world" concepts of risk; and (b) is not used in the

[111] Exhibit B1, Tab 2, Schedule 2, Attachment 1, Page 26; Transcript Volume 2, Pages 42-48.

[112] Exhibit B1, Tab 2, Schedule 2, Attachment 2, Page 23, Presentation "Overview of Three Potential Scenarios".

[113] Exhibit B1, Tab 2, Schedule 2, Attachment 1, Page 23.

actual planning process for its investments, demonstrates a misunderstanding of the purpose and objectives that the reliability risk model is attempting to address.

142. SAIDI and SAIFI metrics capture lagging attributes of real world risk. However, a missing link to these metrics arises when transmission systems, by design, have significant redundancy. It is the condition of these assets that provides redundancy. If equipment condition deteriorates, such that redundancy is reduced, the question becomes whether, and to what extent new investment restores overall system reliability. SAIDI and SAIFI statistics do not measure asset condition or system risk or the degree of system redundancy. They cannot guide planners on investment levels and what level of improvement to system reliability may be achieved from overall investment expenditure. Communicating risk arising from deteriorating asset condition and how this affects system reliability is the issue. What Hydro One's transmission planners have presented and are using is a predictive tool that includes "real world" concepts of risk designed to assess the impact and effectiveness of investment expenditures on system reliability, measured as a leading outcome measure, expressed as a relative value.

143. The fact that this tool is not used to specifically pick and choose investments, but only provides a way to communicate relative outcomes does not mean that the tool does not have a valid purpose. As Mr. Penstone described, past challenges occurred in explaining how investments to extend transmission asset service life provided measureable value to the customer's interests.[114] One of the main benefits in using the reliability risk model was finding common understanding and interests with sophisticated customers and the recognition that all participants in the Transmission system are concerned with the need to manage risk with their major industrial operations and provision of large scale electricity distribution to millions of customers.

144. While Staff appear to take issue with conclusions found in the IPSOS Report, the IPSOS Report fairly reported on the views expressed by transmission customers during the IPSOS Engagement process. The IPSOS Report can and should be relied upon by the Board as demonstrating the reliability risk model provided value and understanding to transmission customers and assisted in obtaining an understanding of customer needs and preferences.

[114] Transcript Volume 5, Page 133.

145. Staff questioned the usefulness of the reliability risk model given the lack of back-cast testing. Mr. Ng explained why this could not be done. The reliability risk model focuses on overall investment expenditure. A reliability risk baseline level is established based on the existing transmission system. In prior years, Hydro One's capital expenditure investments were focused more on development capital programs. Construction of new circuits and new lines is no longer Hydro One's primary focus, rather it is maintaining system reliability through sustainment investments. Because the reliability risk model considers overall investment and focuses on three specific sustainment asset types (breakers, transformers and lines) differences in historical investments would not provide for an apples to apples comparisons as the mix of the investments is different.[115]

146. Staff's criticisms regarding benefits of the model focus on the use of hazard curves. The criticisms focus on how hazard curves focus on asset age and not condition. To be clear, hazard curves depict conditional probability of failure of an asset at any given point of its service life. This hazard function is a well-established branch of mainstream statistical survival analysis used by the insurance and manufacturing sectors.

147. If the reliability risk model was intended for the purpose of asset selection and did so in such a way as selecting assets based strictly on asset age, Hydro One would agree that this would be inappropriate. Replacing assets strictly based on age means once a predetermined age is reached, the given asset will be replaced regardless of condition, which is clearly not Hydro One's practice. However, and as explained above, that is not the underlying purpose of the model. The reliability risk model is an outcome metric to communicate risk; asset selection is not the purpose of the approach.

148. Hydro One acknowledges that go-forward use of the relative risk model would require updating of asset demographic profiles and revision of–hazard curves based on the inclusion of new investment. Any change in hazard curves, asset demographic profiles, and replacement rate associated with Hydro One's fleet would form the basis upon which system reliability risk would be measured. What Staff have not recognized is that younger fleets of assets are less likely to fail relative to older fleets of assets. This is why hazard curves, which quantify conditional probability of failure for asset throughout its service life, are an appropriate and foundational element of the model.

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[115] Transcript Volume 5, Page 124.

d) No Reduction to Capital Budget is Justified

149. At page 17 of its argument, Staff conclude that the Board should not approve the full amount of Hydro One's capital expenditures for the test years. Instead, a reduction of $136 million should be made to each of the test years.

150. The calculation of Staff's reduction amount has two components. The first is based on calculating a five year average of Hydro One's sustainment capital expenditures for the period 2012 to 2016 and deducting this amount from the applied-for sustainment budget and then multiplying this result by 50%.

151. The second component takes 20% of the value of the first component. The resulting amount is intended to provide a "signal" to the company that the quality of the planning evidence and customer engagement activity was below the standard the Board expects from a large, sophisticated utility.

152. Staff's approach is inconsistent with principles of fairness and recognized principles of cost of service regulation. Staff have not reasonably demonstrated which of the capital expenditure areas may be reduced by this amount. Implementation of Staff's approach would result in more than a 25% reduction to the total sustainment capital investment budget. The consequences of this type of reduction to Hydro One are unknown. If Staff had an alternate theory to Hydro One's case, namely, that Hydro One can carry on its affairs and provide safe and reliable transmission services during the test years in the manner described in its Application, but with 25% less sustainment capital investment, it was obligated to make that position known, or at the very least, to put that position to Hydro One's witnesses such that this position could be tested through cross-examination. Only then would the Board have the record it needs to make an informed decision.

153. Staff's proposal effectively represents an alternative sustainment investment forecast; a forecast based on a five year average of historical sustainment expenditure as being appropriate for the test years. Staff's suggestion is that the test year period is no different than the past; that there is no reason to deviate from past approval levels; and that sustainment expenditure investments can and should simply become a mathematical averaging exercise ignoring facts about asset condition and asset need.

154. Hydro One believes that the applied-for capital budget should be approved as filed and that there is no principled basis for Staff's recommendation, as set out in the preceding sections.

e) Line Losses

Reply to Staff submissions on line losses

155. At page 19 of its submission, Staff recommends that Hydro One ensure that the "full cost of losses" are considered when it makes asset design and purchase decisions. Hydro One is unclear whether Staff are suggesting Hydro One implement changes when asset design and equipment purchase decisions are made.

156. This concern in part arises because Staff's recommendation refers to the term "full cost of losses". Staff describe this term to include distribution capacity costs. Hydro One is unaware of any correlation between transmission losses and distribution capacity. This issue was not raised with Hydro One's witnesses. Hydro One's evidence shows that distribution capacity is not considered in all asset design and purchase decisions.

157. Hydro One's evidence is that where new investments are proposed and where selection of new equipment is evaluated, losses are taken into account when it is appropriate to do so.[116] Transformer equipment was an example of where losses are considered. As noted in Exhibit J5.1 the cost of load losses in the context of transformer design and purchase decisions are "based on an NPV assessment that considers the transformer lifetime, loading profile and forecast loading over its life, and the average annual energy costs and the discount rate. Furthermore, Hydro One stated[117] that "…both the cost of core and full load losses into the tender specifications to manufactures for their design and bid. Hydro One selects the best overall equipment considering needs, performance and costs, including losses." Hydro One considers losses and other key performance criteria on a lifecycle basis to purchase the transformer with the best overall economic benefit.

158. Mr. Young explained that in many cases the degree to which losses play a role in the investment decision or equipment selection process is as a screen during the initial

116 Transcript Volume 5, Pages 38-39.
117 Transcript Volume 5, Page 39.

assessment as a secondary or tertiary consideration or when losses are already part of an equipment selection process.[118]

159. Hydro One's current approach to asset design and purchase decisions is appropriate. The consideration of losses should remain dependent on the circumstances and not generalized to a requirement impacting all asset designs or purchase decisions.

Reply to Environmental Defence submissions on line losses

160. ED's argument addresses numerous issues. Hydro One's reply is organized to address four central matters:

1. Need for Scorecard Metric;
2. Addressing Losses in the Transmission Planning/Investment Process;
3. Need for Loss Studies; and
4. Assessment of Capital Cost Investments For Loss Savings.

Scorecard

161. ED requests that "Hydro One be directed to incorporate a metric relating to transmission system energy losses into future scorecards and incentive rate mechanisms."[119] Hydro One has explained that incorporating transmission system losses into future scorecards is not an appropriate metric to gauge a transmitter's performance because *current* is the most significant variable affecting transmission losses, and current is dependent on a wide range of factors that are not within the transmission owner's control.[120]

162. Further support for this fact is found in the "National Grid Strategy Paper" that ED references, on page 21 of this paper.[121] The factor that the transmission owner can control is the *resistance* of the transmission line and by choosing an appropriate line conductor. However, resistance is fixed once the line is built and it remains static for the duration of the life of the line.[122] The opportunities for a material reduction in resistance for the typical levels of line investments are very limited. Even a measure on the

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[118] Transcript Volume 5, Pages 36-37.

[119] ED Submissions, Page 2.

[120] Exhibit K2.1

[121] National Grid, "National Grid Strategy Paper", Revised September 2014, Page 21, online: <http://www2.nationalgrid.com/WorkArea/DownloadAsset.aspx?id=36718> ("**National Grid Strategy Paper**").

[122] Transcript 5, Page 29, Lines 10-20.

incremental changes in resistance would not inform where and what investments to make.

163. At pages 10-11 of its submission, ED states:

> The scorecard proposed by Hydro One provides a significant disincentive to invest in cost-effective measures to reduce transmission losses, even though those measures would lower energy bills and are clearly in the interest of consumers. Hydro One's interests and the interests of consumers are in direct conflict.

164. Evidence in support of this assertion was not provided by ED. Conversely, Hydro One's evidence and testimony addressed the impact of losses to a conductor investment, why such impacts only arise in limited circumstances, and the overall economic impacts lines losses have to ratepayers.[123] Hydro One explained that in calculating the total energy bill, transmission losses cannot be considered in isolation.[124] There are instances where it is more economical and beneficial to rate payers to dispatch lower-cost generation that is further away from load centres but which can lead to higher line losses.

165. For all of these reasons, ED's transmission scorecard proposal should be rejected.

Loss Considerations in Planning

166. At page 2 of its submissions, ED states that Hydro One does not systematically assess cost-effective measures to reduce transmission losses costs, and has not done anything to implement the Provincial Government's "Conservation First" policy and as it concerns Hydro One's transmission business.

167. ED takes an overly broad interpretation of the Conservation First policy. This framework was intended to apply to LDCs and consumers and not directly to Transmitters.[125] Hydro One's evidence shows that it does consider transmission losses in new development projects and the selection of equipment such as transformers where it is cost effective.[126,]

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[123] Exhibit K2.1; see also Transcript Volume 5, Pages 35-39.

[124] Transcript Volume 5, Pages 40-41.

[125] Refer to Independent Electricity Systems Operator, Conservation First Framework, online: <http://www.ieso.ca/Pages/Conservation/Conservation-First-Framework/default.aspx>.

[126] Exhibit K2.1; Transcript Volume 5, Pages 36 -37; Transcript Volume 5, Pages 38-39.

168. Hydro One's evidence is that with the except for very special and limited circumstances, transmission system losses are seldom the primary driver for transmission investments.[127] Mr. Young used the Barrie TS upgrade (ISD #12) as an example to demonstrate why. The investment cost of this upgrade is $80 million. The *lifetime* savings from losses would fund only $2 million of capital.[128]

169. ED's assertion that Hydro One transmission needs to change its practices to align with changes made by distributors demonstrates a misunderstanding of transmission planning. [129] Losses on transmission system, unlike distribution system, are already low due to the inherent transmission system design required to meet transmission reliability standards.[130]

ED's Request for Additional Studies

170. ED states that although Hydro One considers losses in some circumstances, it does not conduct the kind of robust economic assessment that National Grid does.[131]

171. Hydro One believes there is continued confusion relating to the differences between integrated system operators like National Grid, and a stand-alone transmitter like Hydro One. National Grid performs the functions of both integrated system operations and transmission owner and is therefore not an appropriate comparator.[132]

172. Hydro One does not see the value to ratepayers as to why a further study process or review is needed given the limited economic impact that a transmitter has on loss reduction. Detailed losses assessment is a significant undertaking and is only carried out when proven worthwhile.[133] Hydro One's understanding of loss reduction as a driver of transmission system investments is consistent with other major transmission companies.[134]

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127 Transcript Volume 5, Pages 35-36; Additional Evidence, Questions 30-35.
128 Transcript Volume 5, Page 39, Lines 18-26.
129 ED Submissions, Page 8.
130 Transcript Volume 5, Page 36, Lines 12-21.
131 ED Submissions, Page 7.
132 ED Interrogatory Response to Intervenor Evidence, Number 5.
133 National Grid Strategy Paper, Page iii, Executive Summary and Pages 3-4.
134 Transcript Volume 5, Page 35, Lines 5-25.

173. At page 9 of its submissions, Environmental Defence suggests that Hydro One should retain Third Party consultants to help prepare Transmission Loss Reduction Plans.

174. Hydro One submits that ED has not reasonably shown how Hydro One's transmission planning process would materially benefit from this type of expense and the value this would provide to transmission customers.

Assessment of Capital Cost Investments For Loss Savings

175. ED's argument criticizes the example Hydro One provided in its Additional Evidence filed as Exhibit K2.1.[135] The example illustrated the magnitude of the line conductor investments and the small corresponding loss savings that can be achieved. ED asserts that a $1 million annual savings corresponds to $60-$80 million and further suggests that achieving the stated loss savings can be achieved at "incremental cost".

176. ED's submissions do not consider the time value of money and the likely magnitude of the capital costs required to achieve this level of savings. Mr. Young explained that "$1 million would be an annual savings, with current interest rates and inflation this would only justify somewhere between a $15- to $20 million level of investment."[136] This is an order of magnitude lower than the capital costs to replace 1.5% of Hydro One's conductor fleet.

177. ED's suggestion that the loss savings can be achieved at incremental costs, fails to take into account the likely increase in capital costs. ED assumes that the proposed population for conductor replacement can be incrementally up-sized. In most cases, the existing tower designs do not support the larger and heavier conductor necessary to reduce losses. Substantial costs would be incurred to build new towers for the larger conductors. This was explained in the Additional Evidence and in Mr. Young's cross-examination testimony. Furthermore, the purpose of the illustration was to demonstrate that if increased loss reduction was sought from the next 1.5% (or 440km) of the conductor fleet, then the incremental capital cost would be approximately $180 million.

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135 Exhibit K2.1, Question 30.

136 Transcript Volume 5, Page 69, Line 13.

178. Where the driver is transmission loss reduction, very often the transmission capital costs outweigh the loss reduction benefits over the life of the asset.[137] This is further supported in the "National Grid Strategy Paper", referenced by ED's final argument. ED failed to acknowledge National Grid's assertion in the same report stating that "[…] it is not economically justifiable to replace assets if the only driver is the reduction of transmission losses."[138]

f) Benchmarking

Reply to Staff submissions

179. On page 20 of the Staff submission, Staff identified concerns with the reliability metrics provided in the Navigant/First Quartile report on the Total Cost Benchmarking study.

180. The Navigant/First Quartile Study was primarily a total cost benchmarking study and included within it were two different set of reliability metrics. It was not intended to be a comprehensive reliability benchmarking study, and the inclusion of two different sets of reliability metrics is an enhancement, not a flaw, in the study. The CEA statistics provide an indication of the current experience of the majority of customers (those in the more highly populated southern portion of the system). The TADS metrics provide an indication of the reliability/performance of the underlying electric system, across its entire breadth. The fact that they provide different views helps in the understanding of system performance, as well as in helping predict future performance, and therefore investment needs.

181. The use of different peer groups is not a fatal flaw. While Hydro One agrees that it would be optimal to have a uniform peer group, this type of data was simply not available.

182. Staff is correct in noting that transmission metrics that track system outages do not directly track the impact on customers. Transmission system outages historically have relatively limited impacts on customer outages, largely because of redundancies in the transmission network, as well as flexibility in the distribution systems. However, tracking system reliability (i.e. TADS metrics) is very useful in understanding the long-term

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[137] Transcript Volume 5, Page 69.

[138] National Grid Strategy Paper, Page 8.

performance, and helping to highlight imminent and future investment needs before transmission system problems become significant contributors to customer outages.

Reply to AMPCO submissions

183. On page 38 and 39 of AMPCO's submission, AMPCO made several comments about the comparative capital investment of Hydro One, the reliability metrics used, and methodology associated with the study for the Transmission Total Cost Benchmarking Study by Navigant/ First Quartile Consulting.

184. Hydro One's sustaining capital investment was in line with the industry during 2014, for the first time in at least 4 years. In the period prior to 2014, Hydro One's sustaining capital investment level was significantly below the industry norm, for both transmission lines and substations.[139] These extremely low re-investment values for several years provide the appropriate context for evaluating the capital investment plans, rather than a single year in which Hydro One was making necessary sustaining investments.

185. While the Navigant report observed variations with comparable sustainment capital investment averages during the past 5 years, the overall trend is roughly flat, not downward, and it can reasonably be expected that the trend will remain roughly flat. Hydro One is slightly out of alignment within the industry in terms of timing of its growth and sustaining capital investments. Hydro One's investment plan includes levels of investment that will bring the long-term investment rate back to the norms within the industry.

186. AMPCO is correct in noting that having complete knowledge regarding the age, condition, and other demographics of other companies might be helpful in studying any one of them.

187. However, without extraordinary cooperation from the other companies that participated in the study, (combined with great expense) it is not possible to develop an assessment of the condition of the system for each of the comparator companies. In aggregate, however, it is reasonable to expect that the relative condition of assets represents a range similar to that for the industry, and that Hydro One's system condition will be within that range.

[139] Exhibit J3.3, Pages 1-2.

188. On the question of age of system components, one of the elements of the study done by Navigant was a comparison of the relative age of assets as measured by % installed by decade, broken down by poles, towers, conductors, and substation transformers, breakers, and switchgear.[140] Overall, Hydro One's asset base is slightly older than the average, but only in the case of transmission towers is this substantially older than the median. Based on this observation, the Navigant report concluded that age should not be used to try to adjust the results for all the companies. If any bias was introduced into the study by not considering age, it understated the need for Hydro One to replace parts of its existing system.

189. Hydro One's sustaining capital represents a long-term investment. As such, the spending for several years provides an appropriate context for understanding capital spending plans in current and future years. The planned increases in future years are based on the needs as developed through reliability and system condition analysis, but over a span of years, the total sustaining capital investment will be near the median of the comparison panel.

190. As noted in Figure 36 from the Navigant report as referenced by AMPCO,[141] Hydro One is an outlier with respect to costs within the comparator group. It is important to recognize that Hydro One is an outlier on the low side, meaning that the company is spending at a level significantly below that which would be anticipated on the basis of its relative size. This provides clear support for the view that any increases in Hydro One's future investment levels, as supported by asset condition, would move it closer to the levels of the other companies in the benchmark report.

191. The asset base has been repeatedly shown to be the best predictor of spending for transmission operators of varying sizes. Even at the high end of the asset value spectrum (i.e., the largest companies), where Hydro One is placed in its comparator groups, the relationship of spending versus asset values continues to be very strong. Figures 36 and 37 from the Navigant report[142] demonstrate this point clearly and show that asset base is the best available normalizing factor.

[140] Exhibit B2, Tab 2, Schedule 1, Attachment 4, Pages 20-21.

[141] AMPCO Submissions, EB 2016-0152, Page 43.

[142] Exhibit B2, Tab 2, Schedule 1, Pages 35-36.

192. Similar studies conducted by First Quartile Consulting over the past 10 years have consistently had the same result. The asset bases are a very good normalizing factor to use for predicting costs, within this comparator group and within the broader industry.

193. Hydro One's transmission circuits are longer than the average for the industry. Given that, they are subject to greater exposure than companies with shorter circuits. That is the reality faced by Hydro One. Understanding that reality, the company still has the requirement to keep its system operating, without outages, for as much of the time as possible. A circuit outage, whether on a long or a short circuit, has the same impact on the rest of the system. That is why the standard TADS metrics were reported, and mileage-adjusted TADS metrics were not highlighted in the Navigant report.

Reply to SEC submissions

194. On pages 9 and 10 of its submission, SEC drew two specific conclusions concerning the Navigant report:

(a) The peer group selected was not appropriate for the nature of the study, a unit cost study, and appeared to be driven by an added goal – best practices – that did not end up being achieved through the use of the study.

(b) The gross asset value is not an appropriate normalizing factor for spending of utilities.

195. In reply to these two conclusions, Hydro One notes:

(a) The nature of the study was designed to be a total cost study, not a unit cost study. The two approaches are quite different, and a total cost study was the requirement in the settlement agreement and the appropriate approach for this proceeding. The peer group used for the study is a representative peer group for North America, including companies both similar to and different from Hydro One, a logical, standard, and recognized approach to benchmarking. The peer group contains some of the largest transmission operators in North America (including Hydro One) as well as ones with similar weather patterns, voltages, and regulatory regimes. There are also utilities where those factors differ from Hydro One, enabling the group to represent the entire industry. The net result is an appropriate and useful peer panel. At the same time, the peer panel could be described as "good", rather than "ideal". An improvement would have included a larger panel, and one in which both TADS and T-SAIDI/T-SAIFI metrics were available from all participants.

(b) Gross Asset Value has been repeatedly shown to be the best normalizing factor for predicting spending by electric transmission operators.[143] It provides the best possible denominator for comparing both similar and different systems (which themselves are typically built around the demographics of the territory they are in). It also enables comparison of systems in different countries (i.e. the U.S. and Canada) while minimizing the impact of currency fluctuations over time.

196. SEC added a third conclusion, based on the first two, that the use of the Navigant study is of no value to the Board.

197. Hydro One strongly disagrees with SEC's findings. SEC characterizes the Navigant study as a "unit cost study" which indicates a complete misunderstanding of the entire study. The results of the study are clearly valid, based on recognized and appropriate performance metrics for both cost and reliability, along with an appropriate peer group.

198. With respect to SEC's detailed comments found at pages 13-22 of the SEC submissions, Hydro One's reply comments are as follows:

Approach Used by Navigant

199. The basic nature of the argument put forward by SEC in this series of comments indicates a misunderstanding of the study that was performed. To clarify: the study was a "total cost benchmarking study", not a "unit cost benchmarking study".[144]

200. Similarly, the discussion regarding benchmarking of distribution is inappropriate. It is clearly a different business.

201. SEC appears to believe that an econometric study would have been a better choice for methodology. Data availability is a key difference between Distribution and Transmission for an econometric benchmarking study. Specifically, in Distribution, the OEB can compel a large number of Distribution companies to provide complete and

[143] Exhibit B2, Tab 2, Schedule 1, Pages 35-36.

[144] Hydro One Networks Request for Proposal – Tx Cost Benchmarking Study, RFP Number 7000005685 ("**Hydro One RFP**").

comprehensive datasets for an econometric analysis (and even in doing so there are significant data challenges that create uncertainty in benchmarking results). The OEB cannot compel a similar number of transmission companies to provide such a dataset, and no other authority can do so either. That effectively precludes an econometric approach for this study.

202. For this study, as for any total cost benchmarking study, the larger the panel of peers that can be arranged, the better it can be analyzed, but having them all be as similar as possible to the company under study (Hydro One in this case) is not beneficial, and is not reasonably possible. In a practical sense, the comparison panel provides a representative group that reflects the industry, and serves as a useful basis for analysis.

203. In summary, the study was designed to be a total cost benchmarking study, conducted using very straightforward methods. It was not intended as a unit cost study, and other, more complex methods, such as econometric models, are not appropriate given the amount and availability of data required for that approach.

Peer Group

204. The peer group used is representative of the North American transmission utility industry. It has companies that are both similar to Hydro One and those that are different, which provides benefits in understanding the relative position of Hydro One, both in the industry as a whole, and against companies that are quite similar to it.

205. The peer panel used for the study is a reasonable and appropriate panel. In any benchmarking study, the availability of relevant data is the key to developing a comparison panel. For this study, the goal was a panel of companies with similarities to and differences from Hydro One, to achieve a representation of the industry and Hydro One's relative performance within it. The panel of companies used for the comparison certainly meets those criteria.

206. As was explained during the oral hearing, in any benchmark study, a broad comparison panel is a typical goal, and generally, "more is better". In this case, all (100%) of the larger transmission companies in Canada were approached and invited to participate by providing data. Several chose not to. Similarly, a number of the larger U.S.-based transmission operators were invited, and many of them declined. The panel of utilities

eventually included is as broad and valuable as possible. In the net, it is a "good" comparison panel, although falling somewhat short of "ideal", and reflects entities that agreed to participate in a wide ranging invitation process.[145]

207. Voltage level wasn't used as a factor in the study, not because it is unimportant or impossible to gather information about, but because assets are a better normalizer. Voltage differences are one of the reasons that line length is a poor predictor of costs – because the costs of building EHV lines are so much higher on a per-km basis than those of lower voltage lines. By using assets as the primary normalizer, the effect of voltage class is effectively neutralized.

208. On the question of size, Hydro One is indeed larger, with a bigger asset base, than all the transmission operators in the comparison panel. That would be true of any comparison panel that could be composed in North America, with the exception of about five companies. It is one of the unique features of Hydro One that it is among the very largest in North America. The mere reality of large size doesn't make Hydro One incomparable to smaller utilities, and that is the point of using normalizing factors.

Economies of Scale

209. The very fact that the asset base is the best predictor of costs for transmission companies of all sizes, large or small, above about 250,000 customers is evidence that there are no obvious additional significant economies of scale in these large-scale transmission operations.

210. Figure 36, page B-1 of the Navigant report shows a line plot and the associated correlation coefficient demonstrating an extremely strong linear correlation between assets and spending.[146] That relationship has been confirmed over many years of similar studies by First Quartile. Figure 37 demonstrates how much better the asset base is as a normalizing factor than measures of length, capacity, or throughput. Those figures were placed in the report in response to the questions during the stakeholder meeting in which the economy of scale question was raised.

[145] Exhibit B2, Tab 2, Schedule 1, Pages 9-10.

[146] Exhibit B2, Tab 2, Schedule 1, Page 35.

Best Practices

211. The consultants did not "add" this goal to the study. It was part of the original terms of reference for the study as contracted and as determined in consultation with stakeholders.[147]

212. It is unrealistic to anticipate a one-for-one relationship between individual data points and recommended actions. The purpose of gathering multiple data points and in conducting multiple interviews is to create a broad basis for conclusions and development of recommendations.

213. The best practices recommendations were assembled on the basis of the results of the interviews, knowledge about practices of the companies in the peer panel, and knowledge of the consultants involved in the study about practices in place at other utilities.

214. With respect to whether or not all of the recommendations were based purely on the information gathered about the operations of the peer group in this analysis, or somehow diminished because best practices take into account the experience of expert consultants with over 30 years of experience in the area of study, Hydro One submits it was appropriate and beneficial to take advantage of the author's expertise. This was part of the transparent selection criteria used in choosing these particular consultants.

215. SEC's conclusion refers to a different study (unit costs or econometric benchmarking) they would rather have seen conducted, but which is not consistent with the original terms of reference that Hydro One consulted with stakeholders to develop. SEC's assertion represents a bias toward a different type of study which wasn't part of this proceeding. As such, SEC's conclusions and the related commentary should not be relied on by the Board in its assessment of the study.

The Denominator of the Metric

216. As noted, based on empirical evidence over many years, there is no clear significant economy of scale in transmission operations beyond a certain size. Further, the

[147] Hydro One RFP.

empirical evidence suggests the asset base not only addresses the size difference between utilities, it also addresses the demographic differences between utilities.

217. Using an assumption that most utilities have made reasonable design choices over time, the transmission systems reflect the demographics of the service territory for each utility. In addition, assuming that most utilities have performed their construction within a broadly reasonable range of efficiency, the existing systems represent the results of many decades of design decisions and construction execution. At this point, for each company, the transmission system is essentially a fixed asset, and using it as a denominator is reasonable.

218. The asset base is demonstrably the best denominator for comparing the cost performance of transmission operators. SEC makes a reasonable point that the use of that normalizer could lead to some perverse conclusions, but the same would be true if any capacity or asset size measures were used for normalization. Again, though SEC states that "customers value system capacity or throughput", those are clearly inferior normalizing factors in terms of their explanatory capability.

Conclusion

219. SEC has demonstrated no basis for its conclusions, nor any facts that would suggest better conclusions. The results of the benchmarking report were presented objectively, and produced results that are valid and appropriately capture the essence of the study.

B. SCORECARD

220. Hydro One is appreciative of Staff's comments on the Scorecard, and its recognition that development of scorecard metrics is an ongoing and evolving area of work. Hydro One intends to report further during its next rates revenue requirement application on the continued development of its Tier 2 and Tier 3 KPIs including stretch targets for these metrics.

221. Regarding the ability to benchmark scorecard and KPI metrics, as noted in Exhibit I-11-11 the issue is the availability of discrete data that is necessary to provide viable comparisons for benchmarking. Without acceptable comparative data, benchmarking results become suspect. Hydro One will however commit to continue its efforts to find

representative data for scorecard metrics through ongoing discussions with independent benchmarking experts.

222. Staff suggest that trend analysis may be a useful tool for Hydro One to use in comparing its own cost trends and its cost trends with cost trends of other transmitters, rather than absolute measures of cost. While Hydro One will consider these suggestions, obtaining and sharing access to cost information from other transmitters and the public dissemination of this information has been a real and substantial challenge. These are matters that Hydro One will continue to pursue with independent benchmarking experts and industry organizations. Hydro One agrees that it is appropriate to assess its own performance on a year over year, trended basis, using the metrics put forth in the Transmission Scorecard and in the Tier 2 and Tier 3 KPIs.

223. Finally, regarding the adequacy of a simple to understand metric of revenue requirement per kWh sold and/or kW installed as a means to give customers, stakeholders and the OEB an appropriate general measure of Hydro One's cost trends, Hydro One concurs with VECC's observation that metrics normalized by energy delivered, or OM&A and capital costs are not useful comparators. A rising or declining trend in this metric has not been shown by Staff as having any significant measurable correlation to Hydro One's revenue requirement, due to the fixed nature of Hydro One's costs. Adverse trending may be the result of declining kWh sold, rather than poor cost performance. This metric is highly dependent upon the denominator and does not substantively reflect Hydro One's efficiency and productivity. Hydro One agrees that revenue requirement per installed kW may be a useful intra-utility metric.

224. Public dissemination of trends showing declines in load and operational costs remaining constant could easily be misconstrued as an outcome that Hydro One should and could address. Conversely, if load trends were increasing and costs remained constant, suggestions that Hydro One should be rewarded by a more positive metric value would again say little about how value to customers results from efficiencies and effectiveness of Hydro One's programs. Adding metrics for simplicity sake should first be demonstrated to appropriately measure efficiency to Hydro One's operations before being attributed to or for Hydro One's specific scorecard.

C. OPERATIONS, MAINTENANCE AND ADMINISTRATION (INCLUDING COMPENSATION)

a) Expected Decline in OM&A Costs as Capital Spending Increases

225. At page 24 of Staff's argument, Staff suggest that because sustainment capital projects increase in the test years, new assets will replace older ones and it is thus a reasonable expectation that sustainment OM&A spending would be reduced to reflect the assumption that new assets require less operations and maintenance costs than older assets. Staff assert that this expectation is not reflected in Sustainment Operations and Maintenance budgets for the test years and as a result, it would be appropriate for the Board to reduce OM&A costs for each of the test years by $12 million. No justification, in terms of how this amount was derived, or any form of support for Staff's "reasonable expectation" was cited.

226. Hydro One does not agree with Staff's position. Hydro One's Sustaining OM&A was presented in Exhibit C1-2-2, a 56-page document. Appropriate levels of detail were provided on each of the three categories that comprise the Sustaining OM&A budget.

227. Increases in spending during the test years relative to historic bridge year expenditures were explained as being largely attributable to:

- Increases in spending on PCB retirement and waste management to meet regulations;
- Increased work in cyber security to meet recently approved NERC Critical Infrastructure Protection Standards and increasing cyber security threats; and
- Increases in lines preventative maintenance to address worn and defective u-bolts and dampers as well as to carry out additional conductor and shield wire sampling and testing on the deteriorating conductor population.

228. Staff's argument makes no reference or in any way challenges Hydro One's Sustaining OM&A forecast cost justifications. Rather, Staff suggest that based on a "reasonable expectation" an arbitrary $12 million reduction should be made to the forecast.

229. Hydro One's management has and will continue to find productivity gains to reduce costs, offset cost increases and find ways to reduce OM&A. An arbitrary reduction will

result in less work being completed, with negative consequences, as opposed to excess OM&A that should be reduced.

230. Hydro One's Sustaining OM&A requirements for the test years are robust. The forecast amounts reflect real need. The reality is that maintenance cost efficiencies from historical sustainment investment are outweighed by other legitimate sustaining maintenance requirements.

231. Hydro One submits there is no reasonable basis to support Staff's proposed reduction of OM&A.

b) Consistent OM&A Spending in Excess of Approval Levels

232. Staff suggest that comparisons between forecast and actual costs and ROE levels in prior years provides the Board with adequate justification to impose an additional reduction to the OM&A forecast for each of the test years and in the range of $15 million per year.

233. In response, Hydro One submits that Staff's submission, in effect, amounts to unlawful retroactive ratemaking. It is well established that the OEB Act requires this Board to operate under a positive approval scheme of ratemaking and must exercise its rate-making authority on a prospective basis and may not exercise its rate-making authority retroactively or retrospectively.[148]

234. The general presumption against the retroactive operation of statutes is set out in *Young v Adams*:[149]

> [I]t manifestly shocks one's sense of justice that an act legal at the time of doing it should be made unlawful by some new enactment,

235. Prospective rate-making involves only a matching of future costs to future rates. In *Northwestern Utilities Ltd v The City of Edmonton*,[150] ("*Northwestern*") Estey J. (for the Supreme Court of Canada) said the following with reference to the equivalent Alberta legislation

[148] *Union Gas v Ontario Energy Board*, 2015 ONCA 453 at para 82.

[149] [1898] AC 469, at 476.

[150] [1979] 1 SCR 684.

> The statutory pattern is founded upon the concept of the establishment of rates in future for the recovery of the total forecast revenue requirement as determined by the Board. The establishment of the rates is thus a matching process whereby forecast revenues under the proposed rates will match the total revenue requirement of the utility. It is clear from many provisions of the Gas Utilities Act that the Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under rates established for past periods. There are many provisions in the Act which make this clear ….

236. In *Bell Canada v Canada (Canadian Radio-Television and Telecommunications Commission)*,[151] Gonthier J. writing for the court, characterized retroactive ratemaking as ratemaking the purpose of which "is to remedy the imposition of rates approved in the past and found in the final analysis to be excessive."[152]

237. In the same case, Gonthier J. explained that "the power to review its own previous final decision on the fairness and reasonableness of rates would threaten the stability of the regulated entity's financial situation."[153]

238. More recently, the Ontario Court of Appeal in *Union Gas Limited v Ontario Energy Board*[154] upheld the rule against retroactive and retrospective rate-making (absent express statutory authority) and set out three exceptions to the rules: (1) where the Board has made rates interim; (2) where deferral accounts have been approved; and (3) where amounts are demonstrated to be "encumbered"; namely, parties reasonably expected the impugned amounts to be subject to adjustment in the future. None of these exceptions apply in these circumstances as the all prior period amounts were included as part of final orders approving rates revenue requirements.

239. If future rates in this proceeding are set by taking into account historical over or underspending, or over or under earnings, the matching process discussed by the Supreme Court of Canada in *Northwestern* is breached. An attempt to recoup funds from past periods by adjusting future periods effectively amounts to retroactive ratemaking. The approach suggested by Staff has no legal basis and should be rejected by the Board.

[151] [1989] 1 SCR 1722.
[152] [1989] 1 SCR 1722 at 1749.
[153] [1989] 1 SCR 1722 at 1,759.
[154] 2015 ONCA 453.

240. At various points throughout the proceeding, intervenors attempted to analyze aggregate actual OM&A figures relative to past approvals, without consideration to the major factors contributing to the variances. For example, in 2013, actual OM&A included a $40 million credit associated with a property tax rebate. OEB staff properly reflected this adjustment in its five-year calculation of under-spending of $13.6 million. However In 2014, insurance proceeds amounting to approximately $10 million were included as a credit to actuals.[155] This was not included in Staff's calculation. If this was properly included, the average under spend would be approximately $11.6 million.

241. Consideration is not given to the timing of underspend. It is clear that actuals have been in line with OEB approvals in more recent years. As demonstrated in Exhibit I-13-25, average overspent levels, as compared to Board approvals were approximately $2.9 million.

242. The argument to support the $15 million reduction in OM&A for the two test years relies on ROE levels achieved between 2012 and 2015; as shown in Exhibit I-2-30. However, as reflected in Exhibit J-12-3, the OM&A under-spend, excluding the property tax rebate and insurance proceeds, ranges from 30 to 60 basis points over the period of 2012-2014. This range contributes on average to about 9.4% of the total overachievement on ROE.

c) Compensation

243. Staff has recommended Hydro One's applied for OM&A be reduced by $54.3 million in 2017 and $55.3 million in 2018. Of this, $22.6 million or 41.6% of the proposed reduction is specific to compensation in 2017 and $22.6 million or 41% in 2018. Staff provides the following reasons for the proposed compensation reductions:

- Staff submitted that the OEB should reduce the OM&A envelope for recovery from ratepayers by the $12.5 million difference in both 2017 and 2018 based upon the results of the latest Mercer Study Compensation Study (Exhibit K9.8) when compared to the results of the 2013 Mercer Study results, in the EB-2013-0416 distribution case. The latest study shows a reversal of the movement to P50 from the trend of previous studies and uses that finding to recommend to the Board the full

[155] Transcript Volume 13, Pages 20-21.

amount of the overage from P50 be disallowed. In the EB-2013-0416 distribution case, the Board disallowed half of the overage from P50.

- Staff submitted that a further reduction be made that takes into account the results of the Hugessen (Exhibit I-6-57-1) and Towers/Watson (Exhibit I-6-57-2 & Exhibit I-6-57-3) studies in the amount of $700,000 for the CEO and CFO compensation being in excess of P50 levels and an additional $6.3 million (Exhibit TCJ1.6) for the other executives covered in the Towers/Watson study, in each of the test years.
- Staff questioned the value to ratepayers of compensation tied to metrics such as earnings per share as appropriate for customers of a regulated transmission or distribution company. Accordingly, Staff submitted that the LTIP amounts should be removed from the revenue requirement. Staff however was unclear as to the amount of these costs that are embedded in the 2017 and 2018 revenue requirements, and invited Hydro One, in its reply argument to clarify this point.

244. Other intervenors supported portions of Staff's recommended reductions (where specifically identified) and proposed reductions as summarized in Table 1 for 2017 and Table 2 for 2018. The smallest reduction being proposed for 2017 is by AMPCO at $6.3 million and the largest being LPMA at $20.4 million as compared with Staff's recommendation of $22.6 million.

Table 1
Staff and Intervenor Proposed Compensation Reductions
2017 $M

Element	Staff	SEC	CME	AMPCO	EP	CCC	LPMA
Compensation Reduction Resulting from New Mercer Study	12.5	12.5	12.5				12.5
Executive Compensation Reduction to Move to P50	7.0						6.3
Disallow LTIP for CFO & CEO (HO to clarify amount)	3.1						1.6
Share Purchase Reduction		0.6					
Management Compensation Reduction to Move to P50				6.3			
Overall Compensation					20.0		

Element	Staff	SEC	CME	AMPCO	EP	CCC	LPMA
Reduction							
Other Reductions (Compensation, Corporate, Sustainment)						15.0	
Total Reduction	**22.6**	**13.1**	**12.5**	**6.3**	**20.0**	**15.0**	**20.4**

Table 2
Staff and Intervenor Proposed Compensation Reductions
2018 $M

Element	Board	SEC	CME	AMPCO	EP	CCC	LPMA
Compensation Reduction Resulting from New Mercer Study	12.5	12.5	12.5				12.5
Executive Compensation Reduction to Move to P50	7.0						6.3
Disallow LTIP for CFO & CEO (HO to clarify amount)	3.1						1.5
Share Purchase Reduction		0.8					
Management Compensation Reduction to Move to P50				6.3			
Overall Compensation Reduction					20.0		
Other Reductions (Compensation, Corporate, Sustainment)						15.0	
Total Reduction	**22.6**	**13.1**	**12.5**	**6.3**	**20.0**	**15.0**	**20.3**

245. LPMA noted in its argument that they believe that there is probably an overlap to some degree in the proposed reductions suggested by Staff. LPMA suggested some of the compensation proposed reductions may be double counted, particularly in the proposed reductions to corporate management costs and in the reduction related to sustainment OM&A.

246. Hydro One does not agree with Staff's recommended compensation reductions, views Staff's position as punitive, and believes that proposed reductions would not be sustainable or in the best interests of customers. Staff's position is not supported by the

evidence filed in this proceeding. Staff has ignored the positive steps taken by Hydro One in labour negotiations, pension plan restructuring, the strengthening of pay for performance for executives and management, among other things. Hydro One agrees with LPMA's comments and is of the view that proposed reductions represent a **"triple counting"** of compensation elements, as explained below

247. Hydro One cost its work programs utilizing standard Costing of Work Burden Rates are described in Exhibit C1-5-1 pg. 2-5. In the example provided, payroll obligations account for $84.63 of the $135 total or 62.7%. Base Labour and Payroll Allowances account for 56.3% of Payroll Obligations and Company Benefits account for 38.9% of Payroll Obligations, while Government Obligations account for 4.8% of Payroll Obligations.

248. Any reduction in OM&A expenditures associated with work programs or project will already have a very large labour component in it as indicated above. To then layer on additional specific compensation reductions resulting from the latest Mercer Compensation study and the Willis, Towers Watson study would have the effect of triple counting compensation reductions. The Mercer study includes management employees (MCP Bands 5-10) as does the Willis, Towers Watson study. To suggest a reduction of $12.5 million based on the Mercer study, and then a further $6.3 million for the Willis, Towers Watson study, is clearly a double count. When one then considers the amount of labour included in the work program and project budgets, any reduction to those budgets on top of the Mercer and Willis, Towers Watson studies is clearly not only triple counting, but also punitive. Undertaking J10.2 shows the amount of labour estimated to be included in the work programs. It is significant.

Labour in Work Program	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Estimated Labour in Capital	317,396,377	362,360,860	362,315,956	365,303,753	354,849,786	351,973,855
Estimated Labour in OM&A	158,646,126	160,186,809	154,813,070	133,680,230	184,497,859	173,584,299
Transmission Total	**476,042,503**	**522,547,669**	**517,129,026**	**498,983,983**	**539,347,645**	**525,558,154**

*Consistent with Black & Veatch Methodology described in B1-3-10 attachment 1

*Labour includes fully burdened labour cost (including all wages and benefits)

249. Hydro One submits that it is inappropriate for the Board to rely on the compensation reduction recommendations of Staff. The recommended level and methodology of calculating the reduction is unprecedented and ignores all the significant positive measures Hydro One has been able to achieve to minimize compensation costs over the past two years.

250. Hydro One addresses each of Staff's specific reduction proposals below.

Mercer Study (Exhibit K9.8)

251. Staff submitted that the OEB should reduce the OM&A envelope for recovery from ratepayers by the $12.5 million difference in both 2017 and 2018.

Response

252. Hydro One submits this suggestion is punitive. The Board has not previously disallowed 100 per cent of compensation costs above P50. As noted by Staff in the EB-2013-0416 Distribution Rates Case, the Board disallowed half of the overage from P50. If the Board is predisposed to make an adjustment, 50 per cent or $6.25 million should be the maximum reduction considered. Hydro One does not support the targeted reduction of individual components of its compensation envelope and is of the view that the components that comprise total compensation cost are appropriate, as discussed in the following sections.

253. As noted in Exhibit K9.8, Many of the peer companies have Defined Contribution Pension ("DCP") Plans. This has a negative impact on Hydro One's positioning relative to P50. Hydro One has closed the Defined Benefit Plan for non-represented employees and has implemented a DCP. As the DCP was only recently introduced, benefits are not reflected in the Mercer Study results. The Mercer Study does not take into account the positive results of negotiations and pension structure changes. In addition, many of the employee descriptions employed in Transmission are not fully reflected in the Mercer Study as the Study was undertaken for Hydro One's upcoming distribution application and therefore making adjustments based on a study designed for a different business would be arbitrary. This was discussed as follows:[156]

> MR. STEPHENSON: And that the employee profile of transmission only is different from a compensation perspective than all of the Hydro One Networks total; correct? Insofar as it will include more of your construction workforces.
>
> MR. McDONELL: That is correct. And that's why we were making that point that from a transmission business focus the Mercer study does not include -- so fairly heavily populated roles that are found on our transmission business. So what we tend to see on the transmission side is a much heavier focus on construction employees.

[156] Transcript Volume 10, Pages 31-34.

> MR. STEPHENSON: Okay. And for the Power Workers, you are 16 percent above P50 and so forth; correct?
>
> MR. McDONELL: One of the primary drivers for that increase that we received information from Mercers, who obviously conducted the study, was the impact on pensions. I believe ten out of the 17 participants in the Mercer study have defined contribution plans or hybrid plans, they don't have defined benefit plans, and that is a significant factor for that increase to 1.14.

254. Further explanations were provided by Mr. McDonell as follows[157]:

> MR. RUBENSTEIN: And the date of the study captures information as of September 1st, 2016; correct?
>
> MR. McDONELL: The data used for the Mercer study, yes, September 1st, 2016.
>
> MR. RUBENSTEIN: And you say that there were lower base wage adjustments going forward; correct?
>
> MR. McDONELL: Yeah, what we are saying here is with both the PWU and the Society the full impact of what we have previously described as lower base wage increases hasn't fully resulted in the savings that we would expect, because the -- for the PWU we are only two-thirds of the way through that collective agreement, so we have one more year of lower wage increases, and with the Society there will be two more years of lower wage increases, so if we did the study in 2017 and 2018, we would expect to see a more favourable result to market median.
>
> MR. RUBENSTEIN: And I think you were just saying it's your view that Hydro One will improve against the median going forward; correct?
>
> MR. McDONELL: That would be our expectation.

255. The Mercer Study was undertaken to fulfill a Board directive from Hydro One's last distribution application. As such, it is not an accurate reflection of a work force that is employed for a large part of Hydro One's transmission business, as described above. Hydro One encourages the Board to consider these factors in its deliberations respecting the level of compensation in this Application.

<u>Hugessen and Willis Towers Watson Study Findings</u>

256. Staff also suggest a further reduction be made in the amount of $700,000 for the CEO and CFO compensation (being in excess of P50 levels) and an additional $6.3 million for the other executives covered in the Towers/Watson Study, (Exhibit TCJ1.6) in each of the test years.

[157] Transcript Volume 10, Pages 55-59.

Response

257. Hydro One strongly recommends the Board disregard Staff's suggested $7.0 million reduction. In addition to the "triple counting" implication of this reduction that as previously been discussed above, Staff ignore the benefits Hydro One's new executive have already delivered in terms of productivity savings, in addition to the pension cost savings and implementing a comprehensive pay for performance structure for management as described by Ms. McKellar.[158]

> Our new compensation philosophy which was approved by board in August of 2015 is putting a far greater focus, we would say a laser focus on our pay for performance, our variable pay for our senior leaders. We are also putting more focus on accountability and delivering on our outcomes. We want to be market competitive in terms of being able to attract the leaders that we need, and we also want to be affordable.
>
> However, we have completely revised that annual incentive program and the reason is we want the reinforce our principles for pay for performance, we want the be more accountable for the outcomes, and we want to drive the customer centred focus and the high priority of safety in our company. long-term incentive program, and you have had questions about that as well. That is designed to attract and retain our very senior leaders in the company, and it is consistent with market practice. From a compensation perspective, a more commercial focus means we have far greater linkages between our compensation programs, our employee performance, and productivity and efficiencies.

258. Other savings resulting from the engagement of Mr. Vels and Mr. Schmidt was described by Ms. McKellar as follows:[159]

> Exhibit 1-13-9 outlines examples of procurement-related productivity savings, which have been explicitly built into Hydro One's 2017 and 2018 budgets. And TCJ1.17 outlines the productivity savings currently embedded in Hydro One's investment plan. To date Hydro One's new management has challenged its procurement division to examine its processes and determine whether new approaches can be utilized to achieve savings. This has already resulted in quantifiable improvements.
>
> TCJ1.17 outlines the approaches implemented to date, as well as planned enhancements which should result in future productivity savings. And the savings, I should note, are sustainable, they are recurring, and they more than offset any increase to the executive compensation that is associated with the attraction and retention of Mr. Schmidt, our CEO, and Mr. Vels, our CFO. The table of savings is recreated below.

[158] Transcript Volume 9, Pages 212-216.

[159] Transcript Volume 9, Page 217.

In $M		2017	2018
Procurement			
	OM&A	2.1	2.8
	Capital	11.2	21.4
Information Solutions Division (ISD)			
	OM&A	3.4	4.5
Stations			
	OM&A	2.9	3.5
Total			
	OM&A	8.4	10.8
	Capital	11.2	21.4

259. The savings highlighted above significantly exceed the additional compensation costs associated with the hiring of Mr. Schmidt and Mr. Vels. Management has been retained to make fundamental differences to outcomes in all areas and compensation is reflective of prevailing market conditions, commensurate with the skills and experience they bring to the table.

260. The methodology relied on by Hydro One Inc.'s new and independent Board of Directors regarding an appropriate compensation framework that would attract exceptional leadership candidates like Mr. Schmidt and Mr. Vels was reasonable and appropriate in these circumstances. Hydro One was transitioning away from a government owned utility. Appropriate, experienced advice was sought from Huggessen Consulting. The advice Hydro One Inc. received was that appropriate candidates for the CEO and CFO positions was best informed through the development of a "mid case" scenario; one which took into account both a primary reference group and much larger group comprising of 30 companies listed on the S&P/TSX 60 exchanges.[160] The target total direct pay for the CEO was positioned to the average of the four larger utilities in the primary reference group and which were also in the bottom quartile of the broader S&P/TSX 60 index. In similar fashion, the CFO's total direct pay was targeted in this bottom quartile. The approach taken was measured and balanced. It addressed a real and strategic need: attracting the right individuals for a very complex job and within a very dynamic environment. Market principles apply to real employment attraction and retention circumstances. The design and use of a mid-market strategy based on two peer reference groups was sound and reasonable .

[160] Exhibit I-6-57-1.

261. Hydro One's evidence also referred to the Willis Towers Watson market assessments for other senior management positions (Bands 3-4).[161] Compensation was assessed against a peer group comprising 21 different companies including Canadian utilities. These results show that Hydro One is positioned around the 25th percentile in terms of salary and target total cash. Again, this evidence demonstrates that comparisons to Hydro One's peers remain well within a range of reasonableness.

262. Based on the foregoing, Hydro One's evidence should be preferred over Staff's recommended reductions. Staff's position has not demonstrated to be reasonable and therefore should be rejected by the Board.

<u>LTIP</u>

263. Staff questioned the value to ratepayers of compensation tied to metrics such as earnings per share as appropriate for customers of a regulated transmission or distribution company. Accordingly, Staff submitted that the LTIP amounts should be removed from the revenue requirement.

<u>Response</u>

264. The Board should reject Staff's recommendation to eliminate the LTIP compensation component for Hydro One's senior executives. As noted by Ms. McKellar[162]:

> The LTIP is a long-term incentive plan which is designed for senior executives to create longer term value. It also fosters alignment with shareholder interests and supports the achievement of both near-term objectives, but also long-term value creation.
>
> *I am also aware that STIP and LTIP programs are used in management compensation for management employees of both Union Gas and Enbridge, Consumers Gas*.
>
> Yes, I believe these programs do successfully align management, company, customer and shareholder interests. The alignment, as I've said, centres around productivity and efficiencies, and SIP and LTIP programs are designed to be at risk. They only materialize, they only pay out if performance is achieved both on the annual goals, as well as in the long-term goals that are set, and achieving these goals provides our customers and our ratepayers with value.

161 Exhibit I-6-57-2

162 Transcript Volume 9, Pages 212-216.

265. In addition, LTIP for these two roles do have RSUs and PSUs but it is only the PSUs that have EPS as the performance metric. For the RSUs, there are no specific performance metrics and the value of this instrument will be based on the performance of the stock. For both the RSUs and PSUs, strong company performance rewards those eligible for LTIP. Many factors go into stock value, including reducing costs, being more productive, better customer service, more efficient use of capital, improving asset base – all of which are good for the ratepayer as well and do not just result in outcomes that accrue solely to the benefit of the shareholder. Improvements to earnings can be accomplished by reducing costs within rate periods over and above those already identified, and management are incented to do so. Such improvements accrue to customers as costs are rebased, and as such align the interests of shareholders and customers.

266. As a general principle, incentive pay is a best practice for modern compensation strategies. Equity based compensation is widely accepted to be crucial to attract higher quality management who have the skills necessary to make effect real change to benefit customers, costs and excellence. Compensation is paid at market levels. There is a reasonable expectation that these individuals receive LTIP, consistent with market expectations and in return for providing higher levels of performance. Such performance is directed to outcomes, the benefits of which accrue to customers. Hydro One is of the view that skilled executives that are empowered to act are likely to create outcomes to the mutual benefit of customers and shareholders. This alignment is consistent with the Board's RRF.

267. For the reasons above and the fact that the Board as it has approved LTIP for both Union Gas and Enbridge Gas, the Board should grant similar approval for the Hydro One LTIP compensation program.

268. Staff has asked Hydro One to clarify the amount of LTIP costs that are embedded in the 2017 and 2018 revenue requirements in its reply argument. Hydro One's response to Undertaking J10.2 provided the total LTIP amounts included in 2017 and 2018 but that response did not provide a breakdown between OM&A and capital. Hydro One has provided those amounts in the table below. These costs would be capitalized through the Overhead capitalization process (Exhibit B1-3-10 attachment 1). The OM&A portion is $1.13 million in 2017 and $1.75 million in 2018. The revenue requirement impact of the capital amounts are $0.1 million in 2017 and $0.2 million in 2018.

	2017	2018
Total Long-term incentive (From J10.2)	$2.76 million	$4.27 million
OM&A	*$ 1.13 million*	*$ 1.75 million*
Capital	*$ 1.63 million*	*$ 2.52 million*

Compensation Summary

269. Hydro One believes it has made significant improvements to control compensation costs going forward as described in C1-4-1. For example:

- For the period 2016-2018, the total Networks (Transmission and Distribution) work program is expected to increase by approximately 6.0% while the regular headcount is expected to decrease by 3.9 % over the same period. (Pg. 6)
- To address the fluctuating and seasonal nature of work programs, the Company maintains as much flexibility as possible by utilizing a variety of labour resources, including regular, temporary, hiring hall and contract staff. Total Regular employees in 2018 are expected to be 2.7% lower than in 2013. The Company uses casual labour to appropriately supplement its required workforce to complete its capital work program using the lowest cost labour in the context of collective agreements commitments. (Pg. 7-9)
- In the most recent round of collective bargaining with both the PWU and the Society, Hydro One was able to achieve significant paradigm shifts in three key areas. First, instead of traditional base wage adjustments, the parties agreed to lower base adjustments with lump sum payments. This is significant because lump sum payments do not impact other wage sensitive items such as overtime premiums, pensionable credit and other allowances. Second, the parties agreed to introduce "ownership" type compensation in the form of share grants and employee share ownership opportunities in order to engage employees and align their interests with the goals and success of Hydro One. Third, employee pension contributions continued to increase and future pension benefits were reduced. (Pg. 14-15). Specific details respecting PWU and Society negotiations are described at Pg. 15-16 of the same exhibit.
- Hydro One now offers MCP employees a total cash compensation package that consists of a fixed component (base salary) and a variable, at risk pay

component (Short Term Incentive Plan “STIP”). A small number of key leadership employees also have a long term variable pay component (“LTIP”) as part of their compensation. Each of these compensation components is critical to Hydro One’s ability to acquire talent and retain a high performing workforce. In addition, the compensation plan is intended to provide a balance of fixed and variable or “at risk” compensation with a greater emphasis on longer term variable rewards for more senior management.

270. Hydro One believes that Staff have not attributed appropriate weight to these initiatives and as a result, the recommended compensation reduction is punitive. The Board must look at all the positive initiatives Hydro One has implemented and judge the compensation levels included in the Application from the perspective of balancing a point in time analysis with the understanding that many of the concessions negotiated with its unions will not be fully implemented and therefore measureable until 2018.

Other Board Staff Observations/Recommendations

271. Staff have made a number of observations which are inaccurate and not supported by the evidence. These include:

- The 2017 and 2018 OM&A 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.
- The company should refine its methodology for splitting compensation costs between its two regulated businesses, including the allocation of the 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 is somewhat surprised that new employees are not eligible for share grants, which appears to be a step backwards for Hydro One.

Pension Savings

Response

272. Staff assert that the OM&A reduction associated with pensions is not due to any pension cost saving action by Hydro One. This statement disregards the filed evidence. The pension savings are a direct result of action taken by Hydro One and are also a prime example of the value added of the new senior executive talent brought into the organization to control costs and pass along to customers the benefit of labour initiatives undertaken by the Company. It was the decision of Mr. Vels, the new CFO, to advance the pension valuation that resulted in savings of $58 million in 2017 and $53 million in 2018 being passed on to ratepayers. The savings for Hydro One Transmission are quantified in the table below and total $29 million for 2017 and $25 million for 2018.

Cash Pension Costs (Tx) $m

	2017	**2018**
OM&A		
Blue Page (2016-05-31)	18	18
Original (2016-05-31)	29	26
Reduction	**(11)**	**(8)**
Capital		
Blue Page (2016-05-31)	33	32
Original (2016-05-31)	51	49
Reduction	**(18)**	**(17)**
Total		
Blue Page (2016-05-31)	51	50
Original (2016-05-31)	79	75
Reduction	**(29)**	**(25)**

273. Exhibit C1, Tab 4, Schedule 2, Page 3, clearly indicates that the Willis Towers Watson actuarial valuation included updates for the recently negotiated changes in employee contribution rates, and negotiated changes in employee benefits, in addition to updated investment returns, and refreshed actuarial assumptions, in particular new actuarial tables reflecting non-public sector employee groups that reduced the value of future liabilities. Contrary to Staff's assertions, the advancement of the actuarial valuation, the updates for the recently negotiated changes in employee contribution rates, and negotiated changes in employee benefits are "clearly due" to pension cost saving actions initiated by Hydro One. (These changes also referenced in the actual report files at C1-4-2-1 Pg. 2 and Appendix F, Pg. F-5 to F6). Also, whether benefits to customers

are created by exogenous factors, the initiative of new management to find ways to advance benefits to customers, such as this action, reflect on the focus that management has of finding all opportunities to improve operations and reduce costs.

Compensation Reporting

274. Staff suggest that 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 time for the next transmission application and the next Hydro One distribution application to be filed in early 2017.

275. LPMA also agrees with the submissions of Staff that a more comprehensive record of total compensation, including a refined methodology for splitting compensation costs and employee counts between the two regulated businesses would be helpful to all parties, including the Board**.** LPMA also submits that the Board should direct Hydro One to file such information as part of the next transmission application.[163]

276. SEC submitted that Board should require Hydro One to, for its next application, provide a full Appendix 2-K, which sets out on the same basis, total employees per year, as well as the information provided in appendix Undertaking J10.2, as all other utilities are required to do.[164]

Response

277. Hydro One cannot, at this time, fulfill these requests. Hydro One accounting and payroll systems are designed to record payroll costs at the Hydro One Networks level given the integrated nature of its workforce. This is not a new situation. The compensation information filed in this Application is consistent in form to all previous transmission and distribution applications. On a best efforts basis, in response to Undertaking J10.2, Hydro One undertook to revise and recalculate the total compensation payroll table (Exhibit C1 Tab 4 Schedule 1 Attachment 1) to reflect total transmission compensation. Hydro One can commit to provide a similar table in its next transmission and distribution applications as it met the majority of the Board and intervenor requests. For the

[163] LMPA Submissions, Pages 9-12.
[164] SEC Submissions, Pages 53-60.

Distribution filing Hydro One will be utilizing this approach and making further refinements where possible.

Share Grant Restrictions

278. Hydro One does not agree that Staff should be "surprised" that new employees are not eligible for share grants and the suggestion that it appears to be a step backwards for Hydro One.

Response

279. The statement suggests Staff do not understand the trade-offs made as part of labour negotiations as part of the granting of share options. It is actually a cost saving in that new employees are not issued share grants but instead receive a lump sum, have lower base wage increases, and must make higher pension contributions. This was discussed in cross of Mr. McDonell by the PWU[165]:

> **MR. STEPHENSON**: So somebody that was hired, for example, in 2016 into a PWU regular position simply isn't eligible for those share grants, correct?
>
> MR. McDONELL: I believe, yes. And that date, I believe, is July 2015. So any new employees after that date aren't entitled to share grants.
>
> MR. STEPHENSON: So from the perspective of that employee, they took certain -- in effect, they got -- they got the concessions that were in the agreement but didn't get the offset by way of the share grant; correct?
>
> MR. McDONELL: If you mean that they would be paying the higher employee contribution rates without the benefit of the share grant, that's absolutely true.

280. Mr. McDonell provided further clarification of this under Staff examination:[166]

> MR. McDONELL: Well, I mean, one could look at it -- that would be a 3.7 percent increase, so that's one way to look at it, but that would not be the same thing as saying that's a 3.7 percent increase in the base pay.
>
> The other thing that we are trying to point out is that the 2.7 percent share grant that kicks in at 2017 is offset by the employee contributions to their pension from 2015, 2016, and 2017. If you add up the accumulated value or increase of the pension contributions that equates to 2.7 percent, which is the share grant that's paid out in 2017.
>
> MR. MILLAR: Okay. That's what I didn't understand, because if -- yeah, if you look at the next sentence, it says:

[165] Transcript Volume 10, Pages 18-116.

[166] Transcript Volume 11, Pages 182-183.

> "An increase to pension contributions of an average of .7 percent will also be implemented, which brings the total pension contribution increase on average to 2.7 percent since April 1st, 2015."
>
> MR. McDONELL: That's what we are trying to show, how that balances off.
>
> MR. MILLAR: But the increase in pension contributions -- you are talking about the employee.
>
> MR. McDONELL: The employee --
>
> MR. MILLAR: Okay.
>
> MR. McDONELL: -- contribution --
>
> MR. MILLAR: That wasn't clear when I read that
>
> MR. McDONELL: Okay.
>
> MR. MILLAR: -- so I apologize.
>
> So there is no increase in employer contributions that are --
>
> MR. McDONELL: Correct.

281. To provide share grants to new employees would be clearly an increased cost to ratepayers and as such, is not a step backwards as suggested by Staff. If the intention of Staff was to note that it would be positive for employees and the Company in that the interests of new employees would be more aligned, that action, although increasing such alignment, would increase costs to the Company and would worsen the benchmarking progression towards median. As a result, new employees are not eligible for share grants.

OPEB and Pension Accounting

282. Staff notes that Hydro One has historically used a cash-based recovery method for pension costs and an accrual accounting based recovery method for OPEBs. Staff noted that pending the outcome of the OEB consultation initiated in May 2015 (EB-2015-0040) on rate-regulated utility pensions and other post-employment benefits (OPEBs) accounting in the electricity and natural gas sectors, 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 and that it would be reasonable to allow Hydro One to continue recovering its OPEB costs in rates using accrual accounting on an interim basis for the two test years. Staff noted that Hydro One provided a table that depicted a

material difference of $27 million and $25 million between the two methods for OPEBs, for the 2017 and 2018 test periods, respectively.[167]

283. Staff further submitted that it would be necessary to establish a variance account to track the difference between the accrual method and the cash method for the test years to allow 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.

284. The Society and LPMA supports Staff's proposal. SEC disagreed and submitted that the Board should require Hydro One to recover OPEBs on a cash basis, and create a variance account to track the cash and accrual differential. SEC's reasons for its position were:

- First, most utilities who have rebased since the EB-2015-0040 consultation started are using cash basis in the interim period, with the protection of the variance account. This includes OPG who was specifically ordered to do so by the Board.
- Second, in a time when ratepayers are more sensitive than usual to increases in electricity bills, the Board should embrace every opportunity to lower those rates.
- Finally, in SEC's experience, when a utility has to collect a variance account balance from customers, it will collect the full amount without offset. Conversely, when the utility has to refund a variance account balance to customers, it is sometimes seen as an opportunity to seek a rate increase for another purpose, knowing that the impact will be masked by the refund. If there is even a small amount of this factor when the cash versus accrual account is to be disposed, the result is that the utility and customers are more likely to be made whole if the baseline is the cash basis, rather than the higher accrual basis.

Response

285. Hydro One agrees with Staff, LPMA and Society and rejects SEC's position. As noted at C1-4-2, Pg. 1, The Board has previously allowed cash payments related to pension obligations to be recorded in rates (RP-1998-0001). As well, in April 2006, the OEB in its Decision with Reasons approved full recovery of Distribution pension costs included

[167] Exhibit I, Tab 1, Schedule 131.

in OM&A (RP- 2005-0020/EB-2005-0378). Pension costs were similarly approved for Transmission pension costs (EB-2006-0501, EB-2008-0272, EB-2010-0002, EB-2012-0031 and EB-2014-0140); this treatment was continued in Hydro One Distribution's last cost of service application as well (EB-2013-0416). There is no reason to change Hydro One's accounting treatments pending the generic review completion.

286. SEC's suggestion that there would be some form of gaming if Hydro One were to remain on the accrual method is without foundation and should be rejected by the Board.

287. Should the Board direct Hydro One to establish a variance account to track the difference between the accrual and cash method, it should only be for the 2017 and 2018 test years. Tracking difference between accrual and cash will be a very time intensive and manual process, Hydro One would have to go back to 1999 and roll the data forward. This can only be done on a best efforts basis as all of the detailed data required to support a meaningful calculation may not be available.

d) Depreciation

LMPA submissions

288. LPMA's submissions raise issues regarding Hydro One's depreciation forecast stating that the forecast is "systematically biased in favour of the shareholder, at the expense of the ratepayers" and the depreciation and amortization expense on an actual basis has been less than the Board approved amounts for each year in the 2012 through 2016 period.[168]

289. LMPA further states that this over forecasting amounts to $25.4 million on average over this period or 6.8%. LPMA submitted that the depreciation variance is primarily the result of lower in-service additions than approved by the Board, and the Board should therefore reduce the applied for depreciation and amortization expense of $435.7 million in 2017 and $470.7 million in 2018 by 6.8% in each year. This percentage is the average level of over forecasting in the 2012 to 2016 period shown in the above table. This would result in a reduction in the 2017 and 2018 test year expense of $29.6 million and $32.0 million, respectively. LPMA submits that the Board should remove this safety net that Hydro One has built into the revenue requirement.

[168] LMPA Submissions, Page 12.

Response

290. LPMA's recommendation is essentially retroactive rate making and should be rejected by the Board. It ignores the facts with respect to the actual in-service balances being tracked in the in-service variance account which shows a positive cumulative balance over the three year period thus showing Hydro One has corrected the under achievement of Board approved levels. Hydro One's response to I-6-64 shows that the 3 year cumulative value is a positive $167.4 million.

$ Millions	**Actual / Forecast**	**OEB Approved**	**Variance**
2014 Actual	**$914.5**	**$863.3**	**$51.2**
2015 Actual	**$699.1**	**$821.3**	**($122.2)**
2-year total	**$1,613.6**	**$1,684.6**	**($71.0)**
2016 Bridge	**$911.7**	**$673.3**	**$238.4**
3-year total	**$2,525.3**	**$2,357.9**	**$167.4**

D. FIRST NATIONS PERMITS

291. Staff's argument outlines the fact that Hydro One is carrying on negotiations with First Nations regarding new agreements for transmission assets situated on reserve lands. Staff encourage Hydro One to make genuine efforts to resolve permitting issues and ensure First Nation rights are protected and appropriate compensation is provided. The Society has adopted similar positions.

292. As per Exhibit C1, Tab 3, Schedule 7 (pg. 5-6), Hydro One continues to negotiate with those First Nations for which the completion of transfers of title of transmission assets from OEFC to the Company are outstanding. Until such negotiations have been concluded, Hydro One continues to manage these assets under the terms of the transfer orders.

293. Hydro One agrees that respecting First Nations rights and the provision of appropriate compensation are important considerations that have and will continue to be foundational to those negotiations.

E. <u>NIAGARA REINFORCEMENT PROJECT</u>

294. Staff, supported by CCC, CME and LPMA, have observed that Hydro One has now been recovering AFUDC costs associated with the Niagara Reinforcement Project ("NRP") in rates since January 1, 2007, however, completion of this project has not been achieved. Given this, Staff submitted that the time has now come for the OEB to disallow AFUDC costs of 4.6 million in each of the 2017 and 2018 test years, beginning in the 2017 test year.

295. If the OEB decides some compensation should continue, Staff submitted that this should no longer be through rate base at the weighted average cost of capital (WACC), but through a short-term interest rate.

Response

296. Hydro One disagrees with Staff's position and notes that Staff has again made a suggestion for a reduction in the applied-for revenue requirement for 2017 and 2018 without testing its proposal in the hearing process. Hydro One is not collecting WACC on the investment; it collects AFUDC based on the Company's long-term debt cost as per the Board's Decision in EB-2006-0501.

297. As noted by Staff in the EB-2006-0501 transmission rates case decision, the OEB provided Hydro One with relief from the carrying charges that it would incur on the funds (debt) used to finance the 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.

298. Discussions continue to resolve the issues associated with placing this asset in service, and Hydro One is hopeful that a solution will be eventually achieved, but there is no timeframe for resolution of this very complex situation.

299. Given that the Board did not, in its EB-2006-0501 Decision, approve a specific timeframe in which AFUDC recovery would be permitted, and given that the circumstances relating to NRP have not changed since that decision was rendered and remain largely outside of Hydro One's control, Hydro One respectfully submits that it should continue to receive recovery of its AFUDC costs in a manner consistent with the Board's determination in EB-2006-0501. Hydro One believes that the Board should

reject Staff's proposal, as it was not tested during the proceeding and reflects incorrect factual assumptions.

F. TAX AND ACCOUNTING ISSUES

a) Tax Matters

300. Hydro One lost its tax exempt status as a result of the IPO. The consequences flowing from this were that it became subject to the departure tax ("Departure Tax") of $2.271 billion[169] under the payment in lieu (PILs) regime contained in the *Electricity Act* (Ontario) and the tax bases of its assets were stepped up to fair market value. The stepped-up bases in Hydro One's assets for tax purposes can be used to reduce Hydro One's federal and Ontario tax liability in future years through higher capital cost allowance deductions in the calculation of future taxable income.

301. Hydro One excluded both the cost of the Departure Tax and the future benefits associated with the stepped-up cost basis in its assets from the calculation of the revenue requirement on the basis of the stand-alone principle and the benefits follow costs principle.

302. LMPA, the Power Workers' Union and Staff all support Hydro One's position on this issue.

303. LPMA, on this issue, stated in part:

> Hydro One has excluded both the cost of the departure tax and the future benefits associated with the deferred tax asset from the calculation of the revenue requirement. LPMA submits that this is appropriate and should be approved by the Board.
>
> In particular, LPMA submits that the exclusion of the cost and the benefit follows both the stand-alone principle and the principle that benefits follow costs.
>
> LPMA submits that the IPO was a shareholder decision has nothing to do with the operation of the regulated utility and has no impact on the provision of services to ratepayers. The stand-alone principle insulates ratepayers such that only the costs from activities related to the provision of regulated services to ratepayers are included in the revenue

[169] A number of the submissions refer to a Departure Tax liability of $2.6 billion. The difference between $2.6 billion and the $2.271 billion is the amount of Departure Taxes attributed to Hydro One Distribution and Norfolk Power Distribution Inc. See Exhibit J11.13.

requirement of the regulated utility. Based on the stand-alone principle, LPMA submits that the departure tax is recoverable from the shareholders and not from ratepayers.

The benefits follow costs principle dictates that any benefits that occur as a result of costs incurred should flow to the party that paid for the cost. The deferred tax benefit occurs because of the IPO and the shareholders have paid the cost of the departure tax that resulted from the IPO. LPMA submits that since Hydro One incurred the cost of the departure tax and has not proposed to recover this cost from ratepayers, the benefit of the deferred tax asset should also be to the account of Hydro One.

304. SEC has also acknowledged that if the Board concludes that the departure tax was actually paid by Hydro One, it would not be an unreasonable result to give all of the tax benefit to the shareholders.

305. However, SEC asserts that there is alternative characterization of the facts:

that Hydro One did not in substance pay the departure tax; and

that to achieve this result, the Province purchased $2.6 billion of shares in Hydro One contending that since before the purchase, the Province owned 100% of Hydro One, and after the purchase the Province still owned 100% of Hydro One, in substance all the Province did was to give Hydro One $2.6 million.

306. The CME and BOMA also asserted that Hydro One did not in substance incur a cost in paying the departure tax.

Proper Characterization of the Facts

307. It is also irrefutable that the Departure Tax of $2.271 billion was paid by Hydro One.

308. This occurred through five separate wire transfers made on November 4, 2015.[170]

309. It is irrefutable that the tax liability incurred by Hydro One was funded by its shareholder. In order to fund payment of the Departure Tax liability, recapitalization of HOI and its subsidiaries including Hydro One, was necessary. As noted in Exhibits J11.11 and J11.14 several transactions occurred on November 4, 2015, the effect of which was that Hydro One received cash proceeds from the trickle down recapitalization in the amount

[170] See Exhibit J11.16, Attachment 2, wherein description of the five wire transfers made to the Ontario Electricity Financing Corporation ("OEFC") by Hydro One's Manager, Treasury Operations occurred on November 4, 2015.

of $2.271 billion. This investment was reported in the Unconsolidated Financial Statements of HOI and Hydro One for the period ending October 31 and November 4, 2015. At Page 35 of the HOL Financial Statements, reference is made that Hydro One used the proceeds of the share subscription to pay the Departure Tax.[171] These transactions and method of financing the Departure Tax liability was also subsequently recorded in HOL's 2015 Annual Report and audited financial statements.[172]

Hydro One Paid the Departure Tax

310. Hydro One could have funded the Departure Tax liability by borrowing money, selling assets or obtaining capital from its shareholder, the Province of Ontario. What it could not do was seek to recover the Departure Tax liability from ratepayers as the liability to pay the Departure Tax arose from the decision taken by Hydro One's shareholder to pursue the IPO. The method chosen to fund Hydro One's liability does not change the fact that the liability was both incurred and satisfied by payment of the Departure Tax.

311. Asserting that Hydro One did not pay the Departure Tax because its shareholder provided the funds to Hydro One ignores the separate legal existence of the Province of Ontario and Hydro One and the distinction in law and accounting between an expense (the departure tax) and capital (the issuance of equity to the Province).

312. Any suggestion that the Province of Ontario waived or forgave the Departure Tax or determined that it would not require payment of the Departure Tax is not supportable in law. In other words, such a suggestion cannot be characterized as an alternative view of the facts.

313. Subsection 95.1(1) of the *Electricity Act* (Ontario) provides for the remission of an amount payable under Part VI, which is the part under which the Departure Tax is imposed. It states:

> On the recommendation of the Minister of Finance, the Lieutenant Governor in Council may order the Financial Corporation to remit an amount payable under Part V.1 or VI or under section 83.1 of the Corporations Tax Act if the Lieutenant Governor in Council considers it to be in the public interest to do so.

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[171] Exhibit J11.16, Attachment 2, Page 35.

[172] Exhibit A8-01-01, Pages 68 and 91-92 at Notes 7 and 18, Hydro One Limited's 2015 Consolidated Financial Statements.

> Subsection 95.1(2) provides that the remission ordered under subsection 95.1(1) may be total or partial and conditional or unconditional. No remission order was granted to Hydro One.
>
> Subsection 114(1), paragraph (m), of the *Electricity Act* (Ontario) enables the Lieutenant Governor in Council to make regulations, *inter alia*,
>
> exempting any person or class of persons from any provision of this Act, subject to such conditions or restrictions as may be prescribed by the regulations.

314. No regulation was made exempting Hydro One from the obligation to pay the Departure Tax. Hydro One had a legal obligation to pay the Departure Tax as a consequence of the IPO and it paid that liability.

<u>Province of Ontario Incurred a Cost</u>

315. It is not correct to assert, as BOMA does, that the Province of Ontario did not incur a cost "when it returned the "departure tax" receipt to HONI at the time it still owned 100% of the shares of HONI."[173]

316. In paying an amount equal to the Departure Tax for additional shares of Hydro One, the Province of Ontario no longer had the use of such funds.

317. If the Province of Ontario had not funded the Departure Tax liability of Hydro One through the share subscription, it would have suffered the cost, albeit in a different way. The value of Hydro One would have been reduced, resulting in a reduced valuation of the shares of Hydro One for the purposes of the IPO.

<u>Prospectus Disclosure</u>

318. BOMA assert that Hydro One recognized the weakness of its claim to the IPO generated tax benefit by including in its 2015 Annual Report and the prospectus the following statement:

> <u>Risks Relating to Deferred Tax Asset</u>
>
> As a result of leaving the PILs regime and entering the corporate tax regime, Hydro One will recognize a deferred tax asset due to the revaluation of the tax basis of Hydro One's fixed assets at their fair market value and recognition of eligible capital expenditures.

[173] BOMA Submissions, Page 3.

> Management believes this will result in annual net cash savings over the next five years due to the reduction of cash taxes payable by Hydro One. There is a risk that, in future rate applications, the Ontario Energy Board will reduce the Company's revenue requirement by all or a portion of those net cash savings

319. CME similarly states "as demonstrated by the prospectus prepared in connection with the IPO, Hydro One clearly contemplated the possibility that the Board would not permit it to recover in rates the full amount of the taxes which would have been payable by Hydro One but for the deferred tax asset".

320. These assertions are not correct. The statement simply recognizes, as it should, that the revenues of Hydro One are established by application to the Ontario Energy Board, an independent expert tribunal. While Hydro One considers that having regard to the indisputable facts concerning the incurrence and payment of the Departure Tax that the stand-alone principle and the benefits follow costs principle fully support the exclusion of the tax benefit from the revenue requirement calculation, it would have been improper not to include this disclosure in its public documents. There is nothing unique or special concerning the above disclosure. MD&A documents, for example, include other regulatory risk factors impacted by OEB decisions.

b) Accounting Matters

US GAAP

321. Staff has suggested that the Board should, in essence, modify 3 prior Decisions with respect to Hydro One's use of US GAAP for financial reporting purposes as it relates to its regulated businesses for regulatory accounting purposes. Staff's main concern appears to be level of overhead capitalization undertaken by Hydro One under US GAAP. Staff has made the following observations in its Argument.[174]

- 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. 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.

[174] Staff Submissions, Pages 34-37.

- 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.

- 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. 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.

- 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. 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.

- Staff take the view that the OEB could have the increase to OM&A spread 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.

- 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.

- 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. It was granted approval to use Accounting Standards for Private Enterprises as the basis for its 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.

Response

322. As noted at A-6-1 Pg 1, on November 23, 2011, the Board issued its Decision with Reasons in EB-2011-0268, granting Hydro One's request to use United States Generally Accepted Accounting Principles for regulatory purposes in its transmission business. Based on this decision, Hydro One adopted this accounting standard for regulatory purposes. Similarly on March 23, 2012, the OEB approved the Company's request for Hydro One Networks' distribution business to adopt US GAAP for rate setting and regulatory accounting and reporting. Consistent with the OEB's decision affirming the use of US GAAP for rate-setting purposes by Hydro One Networks' transmission and distribution businesses, on April 3, 2012, the OEB approved a similar request to use US GAAP for Hydro One Remote Communities.

323. In its EB-2011-0268 Decision with Reasons (Pg 10-12), the Board noted that it does not regulate the accounting system adopted by any regulated utility for general financial reporting purposes. Unless otherwise constrained by other regulatory requirements, utilities are free to adopt whatever accounting system they choose for such purposes. The Board's primary concern with respect to the choice of financial reporting accounting systems relates to its consideration of any additional costs that may be incurred as the result of maintaining two separate books of account for two separate accounting regimes.

324. The Board went on to say it was satisfied that Hydro One has made a case for its transition to US GAAP for its transmission business, effective January 1, 2012. The Board noted the transition would enable the company to reduce its revenue requirement by a significant amount. This reduction was attributable largely to the varying treatment of capitalization as between MIFRS and US GAAP. The Board noted that this effect was not expected to be universal among regulated utilities, and variations which are not as

significant as the one occasioned by this Application may not be sufficient to justify deviation from the Report's guidance which indicates that it is desirable to have consistency and uniformity across utilities. The Board "will require utilities to explain the use of an accounting standard other than MIFRS for regulatory purposes." But in this case the variation is significant.

325. This effect formed the basis of the support for the proposal of the applicant from a widely diverse group of intervenors. Virtually all of the intervenors regarded the reduction in revenue requirement as an extremely attractive and compelling reason to permit the company to transition to US GAAP.

326. With respect to the concern that meaningful comparisons with other entities will be difficult if Hydro One is on US GAAP and others are on MIFRS, the Board noted that Hydro One Transmission does not have entities in Ontario that can serve as meaningful comparators. Moving to US GAAP may offer advantages in enabling more meaningful benchmarking possibilities.

327. In summary, the advantages of Hydro One transitioning to US GAAP argued in favour of granting the applicant's request to use US GAAP for regulatory purposes. The Board therefore approved all the resulting adjustments to the 2012 transmission base revenue requirement, capital expenditures and rate base as identified by Hydro One is its evidence.

328. Given the Board's Decision for the three regulated companies, Hydro One strongly disagrees with Staff's recommendation that the overhead capitalization practices should now be more aligned with MIFRS.

329. Given the concern expressed throughout its argument for minimizing rate increases, Staff's recommendation would have the opposite effect, given that higher OM&A would result annually. The Board was very clear in its Decision that the impact of not approving the use of USGAAP would have significant impact on customer rates.

330. Hydro One is also concerned that Staff have again put forth a position that has not been adequately tested during the hearing process and is introducing new evidence at this stage of the proceeding. For example, Staff have suggested that 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. No evidence was introduced to support this claim.

331. Hydro One's practice of capitalizing indirect overhead to PP&E is aligned with the full cost of getting the asset in its intended location and for its intended use. Amortization of these costs better aligns the cost of the asset over the period of time that these assets are consumed to provide service to customers.

332. Staff also suggested as a mitigation measure the OEB could approve a transition period of 7 years and calculated the annual increment to the revenue requirement to be approximately $25 million or 1.6% of the total proposed revenue requirement for 2017 and approximately $50 million or 3.3% for 2018.

333. Staff's position is based upon new evidence which did not receive any attention of Hydro One's witnesses. The approach would appear to create ongoing rate shock for customers for a seven year period. The approach followed by Hydro One matches the costs over the period in which the assets are consumed to provide service to customers and results in stable and predictable rates

334. Mr. Chhelavda was asked by Staff several high level questions re moving to IFRS as shown below[175].

> MR. MILLAR: Do you have any intention of moving to IFRS?
>
> MR. CHHELAVDA: No, we do not.
>
> MR. MILLAR: Okay. And why is that?
>
> MR. CHHELAVDA: For a variety of reasons. One is currently we are a US GAAP filer, and we have the right to use US GAAP as approved by the OEB, and further solidified by the fact that Hydro One Inc. has debt securities listed with the Securities Exchange Commission. Many of our peer companies also use US GAAP, so it makes comparisons between our operations and theirs much easier. There is inherently a cost associated with transitioning to IFRS, namely systems, which would be quite significant. And in the year that you adopt IFRS, there would be a significant rate impact to customers based on the changes, or what's allowed to be capitalized under US GAAP versus IFRS.

The Board noted these concerns in its Decisions approving US GAAP for Hydro One.

[175] Transcript Volume 11, Pages 157-158.

The rate impacts were discussed by Staff with both Mr. Jodoin and Mr. Chhelavda:[176]

> MR. JODOIN: So if you could refer to Exhibit C1, tab 3, schedule 3, page 24, as part of other OM&A, we outline for the transmission segment for both the '17 and '18 test years the amount of capitalized overheads.
>
> MR. MILLAR: Okay. So can you give me what the number would be for transmission? I just don't have that in front of me.
>
> MR. JODOIN: Sorry, sorry about that. We are pulling it up on the screen, but it 133 million for 2017 and 135 million in 2018.
>
> MR. MILLAR: Okay. So imagine if you were under IFRS, as I understand, you would not be able to capitalize all that. Is that correct?
>
> MR. CHHELAVDA: That would be correct.
>
> MR. MILLAR: Okay. And the impact on that on a revenue requirement basis would be you'd have to -- it would be under OM&A instead?
>
> MR. CHHELAVDA: That's correct.
>
> MR. MILLAR: Just if we were to play this out, if you took 2017 for an example, the $133 million would come out of your rate base, but instead it would be recovered through O&M, is that right?
>
> MR. JODOIN: That's correct.
>
> The cost of implementing such a system was also described by Mr. Chhelavda as well as audit implications.
>
> MR. MILLAR: Let's imagine the Board is interested in having you pursue the IFRS style capitalization policy with respect to overheads. If the Board were to do that, what, if any, practical considerations should the Board be aware of? And just as an example I gave, would you still be able to get a clean audit opinion with respect to US GAAP, or are there any other things that we might want to be aware of if we were to suggest such a course?
>
> MR. CHHELAVDA: So if overhead capitalization, if the parameters of how what and how we can capitalize changed at this stage -- and I am just thinking out loud -- I do not believe there would be -- that would be something that would impact us in getting a clean audit opinion. The issue is more around how you would practically implement that. I mean, our systems are set up for us to report under US GAAP, so now this would in effect entail keeping two sets of books. There is an exceptional cost inherent in that. So that would be a limiting factor for us.
>
> MR. MILLAR: Okay. So there would be some practical difficulties.
>
> MR. CHHELAVDA: That's right.
>
> MR. MILLAR: Okay, anything else we should be aware of? I am not suggesting there is, I just want to give you an opportunity to give a full answer.

[176] Transcript Volume 11, Pages 159-162.

> MR. CHHELAVDA: You know, aside from the fact of the cost and the administrative burden of keeping two sets of books, those are the two things that jump out of me.

335. Clearly this discussion mirrors all the concerns addressed by the Board in its decisions.

336. Staff also state that 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 and also noted.

337. Hydro One notes that that IFRS 14 is still an interim standard and as such may be repealed by the IASB. As such, Hydro One does not support the position of Staff and believes that the Board should reject Staff's recommendation.

338. OEB staff have cited Canadian Niagara Power Inc. as an example of a utility that was granted OEB approval to use a regulatory reporting framework other than MIFRS, and was also mandated to align its capitalization and depreciation policies with MIFRS requirements. Staff submitted that a similar approach can be taken with Hydro One. Staff contends that this approach should provide ratepayers with longer-term costs benefits and put Hydro One on an equal footing with other utilities in Ontario.

339. Hydro One notes that Canadian Niagara Power Inc. is a distribution company with a rate base of $89.9 million, OM&A of $10.4 million and a revenue requirement of $15.8 million per its EB-2016-0061 application. Hydro One is a significantly larger entity, is a transmitter, and the company does not believe that Canadian Niagara Power is a meaningful comparator, for the purpose of this analysis. Use of Canadian Niagara Power by Staff as an example is the reason in its US GAAP Decision the Board noted that "this effect was not expected to be universal among regulated utilities, and variations which are not as significant as the one occasioned by this Application may not be sufficient to justify deviation from the Report's guidance which indicates that it is desirable to have consistency and uniformity across utilities."

340. For all these reasons, Hydro One believes that Staff's recommendation should be rejected by the Board.

G. <u>OUTSOURCING</u>

341. At page 24 of its submission, Energy Probe makes recommendations that concern the need to benchmark outsourcing contracts. Part of the concern raised appears to be based on the belief that outsourcing to Brookfield Global Integrated Solutions ("BGIS") is now an affiliate contract and that issues related to the Affiliate Relationship Code now apply. As set out below, Hydro One is not and has never been an affiliate of BGIS.

342. During the oral hearing, Hydro One was asked to advise whether the relationship between Hydro One and Great Lakes Power Transmission is an Affiliate Relationship under the Affiliate Relationship Code ("ARC"). In its undertaking response, Hydro One affirmed that the relationship now existing between Hydro One and Great Lakes Power Transmission Inc. ("GLPT") is an affiliate relationship under ARC. This is the case because Hydro One acquired all issued and outstanding voting securities of GLPT in 2016 as was approved by the Board in accordance with EB-2016-0050 dated October 13, 2016.

343. However, while an affiliate relationship now exists between Hydro One and GLPT this does not create or impute an affiliate relationship between GLPT and BGIS. Hydro One's acquisition of GLPT involved the purchase of all outstanding voting securities. BGIS has no direct or indirect ownership or interest in GLPT. Energy Probe's underlying assumption is therefore incorrect.

H. <u>LOAD FORECASTING</u>

<u>Reply to VECC</u>

344. At pages 39-46 of its submission, VECC provides specific concerns with the approach Hydro One has taken to the load-forecast described in its Application. Hydro One's reply to these concerns follows.

<u>Treatment of Demand Response</u>

345. VECC argues that demand response impacts (in addition to other CDM components) should be included in Hydro One's load forecasting models. VECC suggests doing so would result in different forecast growth rates from what Hydro One has assumed.

346. Demand response ("DR") has no impact on growth rates calculated by the load forecasting model because forecast growth rates are based on <u>energy</u> models, and not dependent on the results of DR programs that simply shift energy use to a different period. Hydro One adds the energy impact of CDM to actual load to arrive at gross load used for developing the growth rates that drive the test year gross load forecast. As such, VECC's claim that the model growth rates would be different if DR programs were included in the inputs to the load forecasting models is not correct.

347. Hydro One disagrees with VECCs interpretation of the Board's EB-2006-0501 Decision as support for VECC's views on the proposed treatment of DR in the current Application. As discussed in response to VECC Technical Conference question #43[177], the Board directed Hydro One in EB-2006-0501 to reduce the expected impact of CDM on total Ontario peak to address issues about inclusion of natural efficiency and concerns about the impact of DR programs on weather corrected load. With respect to natural efficiency, Hydro One has used the CDM data from the Ontario Power Authority's 2013 Long-term Energy Plan ("2013 LTEP"), which already excludes natural efficiency as a component of CDM. DR programs reduce actual load during extreme weather conditions so that load becomes less sensitive to weather. Hydro One's weather correction methodology already accounts for the impact of DR in this regard, and therefore it is not appropriate to increase the 2015 pre-CDM weather corrected peak demand by 1,072 MW as suggested by VECC as this would cause a double counting of the DR impact.

348. LDC verified results provided by the IESO no longer include DR. Starting in 2015, DR programs transitioned from a contract-based program to an annual DR auction, which only reports on DR capacity. The auction process does not provide any commitment regarding use, only the level and value of available DR capacity. This change means that DR capacity is inappropriate for use in the load forecasting exercise. Hydro One's exclusion of DR programs from both historical and forecast CDM is appropriate and consistent with the Board's EB-2006-0501 direction.

349. VECCs recommendation that the final CDM-related adjustments made to the load forecast reflect only the impact of energy efficiency programs and codes & standards is in fact exactly what Hydro One has proposed in its Application.

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177 Exhibit TCJ1.07.

Historic CDM Values Used for Modelling Purposes

350. VECC submits Hydro One should be directed to use the "best available history of actual CDM results" in preparing its forecast. Hydro One agrees, and as stated in the Application,[178] in Interrogatory Responses[179] and at the oral hearing[180] , that is exactly what Hydro One has done. Best available information from the IESO with respect to historically achieved CDM (whether actual or the IESO's best forecast) and future CDM targets is used at the time Hydro One prepares its forecast.

351. It is outside Hydro One's control if the IESO subsequently adjusts the "actual" historical CDM amounts following the filing of its load forecast. In all cases, Hydro One has adopted historical CDM values that represent the IESO's best estimate of those actual values as Hydro One has no basis for challenging this information.

352. Consistent with Hydro One's current process, future load forecasts will reflect the best available CDM information from the IESO for both historical years and future forecast targets at the time the Applications are prepared.

Historic and Forecast Energy Prices

353. Hydro One agrees that a consistent data set for historical and forecast electricity prices is optimal for modeling purposes. However, such a consistent data was not available to Hydro One for this Application. Hydro One will examine whether alternative datasets available from other organizations, such as the National Energy Board, or datasets used for the production of the next LTEP, can be used for purposes of preparing Hydro One's next forecast.

Weather Normalization

354. VECC recommends that Hydro One include in its next rate application load forecasts that are based on two different approaches: (1) 31 year weather normalization; and (2) 20-year trend. This recommendation is made despite VECC's acknowledgement that only a small difference was shown to exist in respect of these two approaches when presented in this proceeding.

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[178] Exhibit E1, Tab 3, Schedule 1, Page 7, Lines 11-14.

[179] Exhibit I, Tab 1, Schedule 144, Lines 118-121.

[180] Transcript Volume 12, Pages 141-142.

355. Hydro One believes that a single consistent approach for developing the load forecast should be approved. The 31-year weather normalization approach has been used by Hydro One since 1988 and it is the same approach used by the IESO. This approach has provided consistently accurate results as demonstrated in Table 5 of Exhibit E1-3-1.

356. Introducing a second load forecasting approach as part of the application evidence provides no certainty in terms of which forecast is appropriate and introduces risk that changes may fluctuate from application to application thus imposing historical trending restrictions. Accuracy of the 20-year trend approach over an extended period of time has not been established, and is not appropriate. The 31-year methodology has proven itself to be accurate over time and there is no reason to deviate from this approach. For these reasons, Hydro One disagrees with VECC's recommendation that it provide the results of two different load forecast approaches in its subsequent rate application.

Reply to LPMA

357. At pages 16-17 of LPMA's submissions, LPMA recommends that network billing determinants be increased by 151 MW in each of the test years. This result stems from LPMA's interpretation that Hydro One's network load forecast should be restated due to chronic under-estimations of actual load levels as depicted in Table 6 of Exhibit A-3-1, as updated on December 2, 2016.

358. In reply, Table 6 of the referenced evidence is not limited to charge determinant accuracy associated with the test years, as it includes bridge year information. The appropriate indicator of charge determinant accuracy used for setting transmission rates is provided Exhibit I-4-44.

359. In this Response, Hydro One shows that load forecasts have not been consistently underestimated and which would result in forecast under-estimations of load revenue, as suggested by LPMA. The variance between actual weather-corrected load and the forecast load used to establish transmission rates are both positive and negative, ranging from -3.03% to +1.09% for Network service,-1.40% to +1.30% for Line Connection service, and -1.48% to +1.46% for Transformation Connection service.

360. LPMA is incorrect to suggest that the forecast Network charge determinants have been below actual demand in each of the past 5 years. As the data provided at Exhibit I-4-44 shows, the approved peak demand in 2015 was higher than the actual peak demand.

Reply to AMPCO

361. At pages 45-48 of its submission, AMPCO also takes issue with Hydro One's assumptions and weather normalized data, suggesting that upward trends in weather temperatures exist with a 20 year average data set as compared to the 31 year normalized weather that Hydro One has relied on.

362. Hydro One disagrees with AMPCO's interpretation that a statistically demonstrated upward sloping trend line exists with the 20 year average data set, reflected by warmer temperatures. As discussed in response to VECC Technical Conference question #46[181] the trend is statistically insignificant. This is because over the years 2011 to 2016, both the high values and low values on the graph decline over time indicating a negative trend. In contrast, over the years 2001 to 2011, the opposite could be observed (both highs and low were increasing).

363. Further, higher temperature does not necessarily lead to higher revenues for Hydro One. The transmission charge determinants depend on all 12 monthly peak values within a year and not on summer peak alone. In other words, higher temperature over the whole year may result in higher revenue during summer months, but also leads to lower revenues over the winter months. The effect of 12 monthly average values, combined with the statistical insignificance of the trend explains why the impact of 20-year trend on the load forecast results was insignificant.

364. AMPCO claims that use of a 20-year trend will result in a load forecast that "better reflects the more normal or expected weather conditions". Hydro One disagrees. This certainly was not the case for 2015 and 2016. As Mr. Andre stated in his testimony,[182] the 2015 and 2016 load forecast adjustment to partially reflect the impact of a 20-year trend that Hydro One agreed to for the purposes of settlement in Hydro One's application EB-2014-0140 contributed to an additional variance of 0.5% between the actual results and the approved forecast in 2015 and 2016. This settlement adjustment

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181 Exhibit TCJ.07.

182 Transcript Volume 12, Pages 176-177.

is a contributing factor to high forecast load approved in 2016 that leads to the 2.1% bill impact resulting from resetting of the load forecast in 2017.

365. Hydro One's undertaking response found in Exhibit J12.9B shows that use of the 20-year tend does not materially impact the charge determinants proposed in this Application at Table 3 of Exhibit E1-3-1. As such, Hydro One submits that no change to its proposed load forecast for 2017 and 2018 is justified based on the reasons suggested by AMPCO.

Reply to CME

366. At pages 25-26 of its submissions, CME raises concerns regarding the levying of network service charge ("NSC") and requests that Hydro One provide a report in its next rates application addressing how the NSC can be modified to ensure industrial customers shifting demand to off peak hours (7 p.m. to 7 a.m.) are not penalized when the system peak occurs in this off-peak time period.

367. In reply, the currently approved NSC determinant was established to encourage and reward customers for avoiding the transmission system peak.[183] If current customer demand is such that shifting customer load patterns has resulted in the system peak falling outside the 7 a.m. to 7 p.m. window, transmission customers should be expected to respond to the change and take steps to avoid the system peak even if it falls outside the 7-to-7 window, as per the original intent of the NSC determinant.

368. The changes proposed by CME are inconsistent with the principles underlying the OEB's original decision in RP-1999-0044 for setting the NSC determinant.[184] The CME proposals would favour certain customer groups (manufacturing and industrial) at the expense of other transmission customers given that a change in methodology that decreases the charges to one group will, by necessity, increase the costs to other customer groups.

369. Without this substantive issue first being addressed, Hydro One does not see the value of being required to prepare the report as proposed by CME.

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[183] Exhibit I, Tab 9, Schedule 16, Part (b).

[184] Exhibit I, Tab 9, Schedule 16, Part (b).

370. That said, if the Board intends to review this issue at Hydro One's next rates application, and would find the information requested by CME to be of assistance in its consideration, then Hydro One is prepared to provide the requested information as part of its next application.

I. EFFECTIVE DATE OF THE BOARD'S DECISION

371. CCC and SEC propose having the date of any rates order arising from this proceeding not take effect on January 1, 2017, but instead the date of any rate order approval. Justification for this is essentially based on the view that Hydro One should have known better; that the time taken following January 1, 2017 to receive a rates order decision was within Hydro One's control, and so it should bear the consequences of not having filed its Application earlier than it did.

372. Hydro One disagrees.

373. At the outset, Hydro One notes that the last transmission application which involved an oral hearing was EB-2010-0002 for the 2011 and 2012 test years. Hydro One filed its evidence on May 19, 2010 and the Board rendered its Decision on December 23, 2010. The rate order was approved on January 18, 2011 in time for rates to be effective in time for January 1, 2011. Hydro One filed this Application on May 31, 2016, essentially within the same timeframe of the last full hearing.

374. Hydro One conducted itself appropriately in the preparation and filing of a comprehensive application that addressed new filing requirements, such as the RRF, a Transmission System Plan and the conduct of additional Customer Engagement activities. Discovery processes leading up to the 12 full day hearing were extensive, yet Hydro One did not miss any filing deadlines regarding these processes. In its past two rates revenue requirements applications settlement processes were used. The Board's decision not to pursue this option in this proceeding was stated at the conclusion of the Presentation Day held on September 8, 2016. The two-day Technical Conference held in late September gave rise to additional and numerous undertaking responses, all of which were prepared and filed on tight timelines. The original hearing dates for the oral hearing proceeding were deferred. Timing of cross-examination at the hearing itself in most cases exceeded original estimates. A great deal of time was taken during the oral hearing to address issues that had received little or no canvassing during the discovery

process. The treatment of IPO related costs including the departure tax is one example. Other issues, such as the treatment and understanding of line losses, added complexity and time to address which could not be anticipated.

375. In sum, CCC and SEC's belief that Hydro One should have known or ought to have anticipated the complexities and timing constraints by filing its Application sooner than it did is not reasonable. Hydro One filed its Application on a date which allowed for a sufficient amount of time for the purposes of a December 2016 decision. CCC and SEC's proposed effective dates are without merit.

III. CONCLUSION

376. Hydro One submits that the evidentiary record supports the applied-for relief as amended by the commitments addressed in this submission. The requested relief is supported by facts; those that demonstrate the justness and reasonableness standard is met. The Application not only conforms with the Board's RRF, it is based on asset and system needs, customer needs and preferences, and an awareness of rate impacts for the customer.

377. This is a transformative time for Hydro One. Efforts underway now are introducing changes, positive changes that will benefit ratepayers; that align Hydro One's interests with those described in the RRF – namely Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance. It is those developments that Hydro One now seeks to build upon.

378. As Mr. Schmidt and Mr. Vels stated at the outset of this proceeding, Hydro One is striving to become a best-in-class, customer-centric commercial utility with a culture of continuous improvement and excellence in execution. Efforts are being undertaken differently under new leadership. New governance frameworks are in place. Increased commercial orientation means greater customer focus, productivity and efficiency, and corporate-wide accountability for outcomes. New senior leadership is working to achieve targeted commercial objectives. These outcomes have been laid out as evidence (Scorecard) in this proceeding, and the Company intends to track, measure and report on these to stakeholders and customers. This approach entails careful and deliberate scrutiny of all costs and investments, and a commitment to act as responsible stewards of the transmission system by asking for "no more and no less than is needed",

and then delivering on the commitments made. This mentality is taken and driven from the independent board to senior management and throughout the organization.

379. This is not just talk. Savings and productivity efficiencies arising from Hydro One's new management team have happened, and are already accruing to customers. New leadership is at the beginning of the process of taking an organization from "good" to "great". Status quo is not the goal.

380. Hydro One is seeking the Board's acknowledgement of these transformative changes and its approval to allow Hydro One to continue to pursue the new course that it has set. It is a challenging course requiring sophisticated leadership, independent governance and leadership who can implement change. Approval of this Application allows Hydro One to pursue this course and work hard to achieve these objectives.

381. For these reasons, Hydro One submits revenue requirements as applied for and as amended in these submissions should be granted and made effective as of January 1, 2017.

All of which is respectfully submitted this 16th day of February 2017.

HYDRO ONE NETWORKS INC.

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Appendix "A"

ISD	Projects	Regional Planning Documents (Reference in EB-2016-0160 B1-2-3 if available)	Hyperlink to Published References
S1 1	Elgin TS - Station Reinvestment	Burlington to Nanticoke Needs Assessment	http://www.hydroone.com/RegionalPlanning/Burlington/Documents/Needs%20Assessment%20Report%20-%20Burlington%20to%20Nanticoke%20Region.pdf
S1 3	Gage TS - Station Reinvestment	Burlington to Nanticoke Needs Assessment	http://www.hydroone.com/RegionalPlanning/Burlington/Documents/Needs%20Assessment%20Report%20-%20Burlington%20to%20Nanticoke%20Region.pdf
S1 5	Nelson TS - Station Reinvestment	London Area Needs Assessment	http://www.hydroone.com/RegionalPlanning/LondonArea/Documents/Needs%20Assessment%20Report%20-%20London%20Region%20-%20April%202,%202015.pdf
S1 6	Palmerston TS - Station Reinvestment	Greater Bruce-Huron Region	http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf
S1 7	Wanstead TS - Station Reinvestment	Chatham-Kent/Lambton/Sarnia Needs Assessment	http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf
S2 0	Aylmer TS – Integrated Station Component Replacement	London Area Needs Assessment	http://www.hydroone.com/RegionalPlanning/LondonArea/Documents/Needs%20Assessment%20Report%20-%20London%20Region%20-%20April%202,%202015.pdf
S2 7	Chenaux TS – Integrated Station Component Replacement	Renfrew Region Needs Assessment (Attachment 14)	http://www.hydroone.com/RegionalPlanning/Renfrew/Documents/RIP%20Report%20-%20Renfrew.pdf
S3 4	Hawthorne TS – Integrated Station Component Replacement	Greater Ottawa RIP (Attachment 3)	http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/RIP%20Report%20Greater%20Ottawa.pdf
S4 1	Minden TS – Integrated Station	South Georgian Bay/Muskoka Needs	http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Documents/Needs%20Assessment%20Report%20-%20South%20Georgian%20Bay-Muskoka%20-

ISD	Projects	Regional Planning Documents (Reference in EB-2016-0160 B1-2-3 if available)	Hyperlink to Published References
	Component Replacement	Assessment	%2003%20Mar%202015.pdf
S42	Mohawk TS – Integrated Station Component Replacement	Burlington to Nanticoke Needs Assessment	http://www.hydroone.com/RegionalPlanning/Burlington/Documents/Needs%20Assessment%20Report%20-%20Burlington%20to%20Nanticoke%20Region.pdf
S47	St. Isidore TS – Integrated Station Component Replacement	Greater Ottawa Needs Assessment	http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/Needs%20Assessment%20Report%20-%20Greater%20Ottawa%20-%20Outer%20Ottawa%20SubRegion.pdf
S50	Strathroy TS – Integrated Station Component Replacement	Strathroy TS Local Plan	http://www.hydroone.com/RegionalPlanning/LondonArea/Documents/Local%20Planning%20Report%20-Strathroy%20TS.pdf
D12	Barrie TS Upgrade	Southern Georgian Bay/Muskoka Needs Assessment	http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Documents/Needs%20Assessment%20Report%20-%20South%20Georgian%20Bay-Muskoka%20-%2003%20Mar%202015.pdf
N/A	Overbrook TS EOL Transformers	Greater Ottawa RIP (Attachment 3)	http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/RIP%20Report%20Greater%20Ottawa.pdf
N/A	Hawthorn Autotransformers Replacement	Greater Ottawa RIP (Attachment 3)	http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/RIP%20Report%20Greater%20Ottawa.pdf
N/A	Hawthorn EOL Stepdown Transformers Replacement	Greater Ottawa RIP (Attachment 3)	http://www.hydroone.com/RegionalPlanning/Ottawa/Documents/RIP%20Report%20Greater%20Ottawa.pdf
N/A	Gardiner T1/T2 Like-for-like Replacement	Peterborough to Kingston Needs Assessment (Attachment 10)	http://www.hydroone.com/RegionalPlanning/Peterborough/Documents/RIP%20Report%20-%20Peterborough%20to%20Kingston%20Region.pdf

ISD	Projects	Regional Planning Documents (Reference in EB-2016-0160 B1-2-3 if available)	Hyperlink to Published References
N/A	Dobbin TS T2/T5 Replacement	Peterborough to Kingston Needs Assessment (Attachment 10)	http://www.hydroone.com/RegionalPlanning/Peterborough/Documents/RIP%20Report%20-%20Peterborough%20to%20Kingston%20Region.pdf
N/A	Orangeville TS EOL Replacement	South Georgian Bay/Muskoka Needs Assessment and Orangeville TS Local Plan	http://www.hydroone.com/RegionalPlanning/SGB-Muskoka/Documents/Local%20Planning%20Report%20-Orangeville%20TS%20EOL%20Replacement.pdf
N/A	Wingham TS - Station Refurbishment	Greater Bruce-Huron Region	http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf
N/A	Seaforth TS - Station Refurbishment	Greater Bruce-Huron Region	http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf
N/A	Hanover TS - Station Refurbishment	Greater Bruce-Huron Region	http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf
N/A	Stratford TS - Station Refurbishment	Greater Bruce-Huron Region	http://www.hydroone.com/RegionalPlanning/GreaterBruce-Huron/Documents/Needs%20Assessment%20Report%20-%20GreaterBruce-Huron%20Region.pdf
N/A	St. Andrew TS - Station Refurbishment	Chatham-Kent/Lambton/Sarnia Needs Assessment	http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf
N/A	Scott TS Autotransformer Like-for-like Replacement	Chatham-Kent/Lambton/Sarnia Needs Assessment	http://www.hydroone.com/RegionalPlanning/Chatham/Documents/Needs%20Assessment%20Report%20-%20Chatham-Kent-Lambton-Sarnia.pdf
N/A	Glendale TS - Station Refurbishment	Niagara Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/Niagara/Documents/Needs%20Assessment%20Report%20-%20%20Niagara.pdf
N/A	Stanley TS - Station Refurbishment	Niagara Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/Niagara/Documents/Needs%20Assessment%20Report%20-%20%20Niagara.pdf

ISD	Projects	Regional Planning Documents (Reference in EB-2016-0160 B1-2-3 if available)	Hyperlink to Published References
N/A	Thorold TS - Transformer Replacement	Niagara Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/Niagara/Documents/Needs%20Assessment%20Report%20-%20%20Niagara.pdf
N/A	Crowland TS - Transformer Replacement	Niagara Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/Niagara/Documents/Needs%20Assessment%20Report%20-%20%20Niagara.pdf
N/A	Kirkland TS Transformer	North/East of Sudbury Needs Assessment	http://www.hydroone.com/RegionalPlanning/NE-Sudbury/Documents/Needs%20Assessment%20Report%20-%20North%20and%20East%20of%20Sudbury.pdf
N/A	Otto Holden TS Autotransformers	North/East of Sudbury Needs Assessment	http://www.hydroone.com/RegionalPlanning/NE-Sudbury/Documents/Needs%20Assessment%20Report%20-%20North%20and%20East%20of%20Sudbury.pdf
N/A	Morrisburg TS: Protection Upgrade	St. Lawrence Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/St-Lawrence/Documents/RIP%20St%20Lawrence.pdf
N/A	Smith Falls TS: Protection Upgrade	St. Lawrence Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/St-Lawrence/Documents/RIP%20St%20Lawrence.pdf
N/A	St. Lawrence TS: Breaker Replacements and Protection Upgrade	St. Lawrence Region Needs Assessment	http://www.hydroone.com/RegionalPlanning/St-Lawrence/Documents/RIP%20St%20Lawrence.pdf
N/A	Keith EOL Transformers, Tilbury TS	Windsor-Essex RIP (Attachment 9)	http://www.hydroone.com/RegionalPlanning/Windsor-Essex/Documents/RIP%20Report%20Windsor-Essex.pdf