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BY EMAIL and RESS

February 1, 2017
Our File: EB20160160

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2016-0160– Hydro One Transmission 2017-2018 – SEC Final Argument

We are counsel to the School Energy Coalition ("SEC"). Enclosed, please find SEC's Final Argument.

Yours very truly,
Jay Shepherd P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally, SEC (by email)
Applicant and intervenors (by email)

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EB-2016-0160

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act 1998*, Schedule B to the *Energy Competition Act*, 1998, S.O. 1998, c.15;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an Order or Orders approving or fixing just and reasonable rates and other service charges for the transmission of electricity as of January 1, 2017 and January 1, 2018.

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

February 1, 2017

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1 OVERVIEW

1.1 Introduction

1.1.1 Hydro One Networks Inc. filed an application with the Ontario Energy Board ("the Board" or "OEB") pursuant to section 78 of the *Ontario Energy Board Act, 1998*, for an order setting transmission rates for 2017 and 2018 (the "test years" or "test period"). Hydro One seeks an annual increase in rates of 2.6% in 2017 and 4.8% in 2018. As discussed in detail in this argument, the increased revenue requirement proposed, and the rates that flow from it, are neither just nor reasonable.

1.1.2 This is the Final Argument of the School Energy Coalition ("SEC").

1.1.3 The ratepayer groups who intervened in this proceeding have worked together throughout the hearing to avoid duplication at all stages, including the oral hearing, and in some cases, also exchanging partial drafts of their final arguments as well as having extensive dialogue amongst ourselves in the determining of final positions. SEC has been assisted in preparing this Final Argument by the co-operation amongst parties in this process.

1.2 Context

1.2.1 Hydro One's revenue requirement increase in this application is primarily driven by the significant planned increase in its capital program. The increase from 2016 is entirely due to the impact of additional capital spending through the increase in the cost of capital of a growing rate base, depreciation and taxes.[1]

1.2.2 Hydro One is proposing to spend $2.2B on capital during the test period. This is a 25% increase over what was sought and approved in the last application for a similar 2 year test period. [2] $1.6B of that capital spending is for sustaining capital, an increase of 43% over what was approved in the last application.[3]

1.2.3 This is all occurring while its reliability is thein the first quartile as compared to other Canadian utilities, and is improving.[4] Hydro One should be proud of this reliability performance. It shows

[1] A-3-1, p.8 (updated)
[2] A-3-1, p.13
[3] *Ibid*
[4] B1-1-3, p.24-25

they have been investing at a level that is prudent to maintain the reliability of its system.

1.2.4 What is striking about this is that the overall capital plan has changed so significantly from what Hydro One planned to spend in the test years during its last application filed in late 2014.[5] In fact, as became apparent during the proceeding, it is also significantly higher than what Hydro One had planned to spend in the fall of 2015 when it shelved the business plan that it was developing.[6] Not only is Hydro One's proposed capital spending significantly above its historical and past planned levels, it is forecast to continue to increase in the future. This has all occurred after Hydro One's initial public offering ("IPO"), which has significantly altered its ownership structure. Since in-service additions will generally lag capital expenditures for a transmission utility, where projects span multiple years, the actual rate increases of the capital expenditures that have been discussed through the application mask the expected increase over time of its new capital plan.

1.2.5 The increase in capital spending has also come during a time when Hydro One did not have a proper business planning process to determine if the spending levels were appropriate. Until midway through the oral hearing, Hydro One did not have either a corporate-wide or a transmission specific business plan.[7] While it claimed that the application itself contained the elements of the transmission plan[8], this distorts the proper planning process which would expect a corporate-wide approved process to determine the elements of a proper capital and operating plan. This transmission application is supposed to be an output of a proper planning process. The need for a business plan guiding Hydro One's planning was even more critical in the lead up to this application, since it has no strategic plan. [9]

1.2.6 Hydro One has defined this application as one of change and transformation due to the decision by its, at the time, sole shareholder (the Province of Ontario) to begin the process to sell a majority stake in Hydro One's parent company, Hydro One Limited ("HOL"). In Hydro One's view, it is transitioning from a Crown-owned corporation to one which is "commercially oriented".[10] While the decision to change its ownership structure is its shareholders' to make,

[5] EB-2014-0140, A-16-8, p.3 (K1.2, p.29)
[6] J9.2
[7] See K8.1, I-6-3 (SEC IR #3), I-13-6 (CCC IR #13)
[8] Tr.1, p.32-33
[9] I-13-6 (CCC IR #13)
[10] Tr.1, p.20-21

since it does not trigger any legal approvals required from the Board,[11] the role of the Board in this proceeding is to ensure that the decision has had no adverse effects on the rates that ratepayers are charged. This is so because regardless of the ownership structure, those rates must be just and reasonable.

1.2.7 Hydro One's transmission operations have had a long history of over-earning. Hydro One's return on equity ("ROE) performance demonstrates that the Board must closely scrutinize the forecast costs and revenues in this application. In each year between 2012 and 2015, it earned a return above its approved ROE, in some cases significantly. It is once again forecasting to do so in 2016.[12] In a cost of service environment, as Hydro One has been in for each of those years, a slight over or under earning is expected as forecast costs and revenue differ from those approved. But significant increases over a sustained period of time demonstrate that Hydro One has either over-forecast costs, under-forecast its revenue or, as shown in Undertaking J12.3, both. A close scrutiny of Hydro One's forecast costs in this proceeding are required.

Actual versus Allowed ROE					
	2012	**2013**	**2014**	**2015**	**2016**
Allowed ROE	9.42	8.93	9.36	9.3	9.19*
Actual ROE	12.41	13.22	13.12	10.93	11.7*
Variance	***2.99***	***4.29***	***3.76***	***1.63***	***2.51***

* Annualized Q3 results *Source: I-20-30, Hydro One Ltr dated November 23, 2016*

1.3 Business Planning Process Flawed

1.3.1 The increase in capital spending set out in this application is based on planning that Hydro One has done in the absence of a proper business planning process.

1.3.2 One of the most difficult parts in reviewing the application has been trying to understand Hydro One's planning process in developing the application. In most rate applications that SEC has reviewed, the starting point in trying to build an investment plan is a strategic vision for the company, set by management and approved by the Board of Directors. The vision, either contained in a strategic plan, a business plan, or both, guides how management is supposed to execute the vision of the company in its budgeting processes. Hydro One appears to have the

[11] In many circumstances a change in ownership structure requires approval by the Board under section 86 of the *Ontario Energy Board, 1998*.
[12] Hydro One' Letter November 23, 2016 providing response to Motion Decision on Motions for Full and Adequate Responses to Interrogatories and Technical Conference Questions released on November 1, 2016.

entire process reversed. It started with a budget, and then developed the business plan. The Board's recent Utility Handbook to Rate Applications has recognized the importance of the business plan.[13] The business plan which underlies this application was only approved by Hydro One's Board of Directors not only after the filing of the application, but months later, during the oral hearing.[14]

1.3.3 In Hydro One's last transmission application filed in 2014, it presented in its evidence a capital plan that spanned not just the two year test period, but until 2019.[15] The evidence was based on a detailed planning process based on a strategic vision of the company.[16]

1.3.4 SEC recognizes that system needs and the planning process are not static. It will invariably change between rate applications as required based on new information and requirements. But what is important is that any wholesale change to a utility's budget and the development of a Transmission System Plan, is being done in a rigorous and thoughtful way. Not one that is rushed to meet the deadline of a rate application, which is what, ultimately, appears to have happened with Hydro One.

1.3.5 Hydro One was in the process of developing its business and investment plan into the late fall of 2015. It had a list of potential investments and had optimized them (May 2015).[17] That outcome was reviewed by the Chief Operating Officer, the senior executive responsible for asset management, who provided comments and changes were made to the investment plan (Summer 2015).[18] Hydro One's Board of Directors hired a new CEO and CFO around the same time, and then they took part in the planning process, including reviewing the draft investment plan (November 2015). All of this was based upon the business planning process that it had in place since the last application.

1.3.6 Around the same time as the review by the CEO and CFO, the IPO took place. After having a discussion with the Board of Directors in the late fall of 2015, management decided to undertake a detailed review of the organization. This was to "review the organization with several goals including a review of the potential for additional productivity and efficiencies, launching a

[13] Handbook to Utility Rate Applications, p.10
[14] Tr.1, p.-17-18
[15] EB-2014-0140, A-16-8 (K1.2, p.23-26)
[16] EB-2014-0140, A-518 (K1.2, p.22)
[17] J8.1, Attachment 1, p.1
[18] *Ibid*; J11.6

customer consolation process, and improving analytics related to the impact of the investment on transmission reliability".[19]

1.3.7 The process that led to the draft business plan had taken approximately seven months. At the last moment, Hydro One decided to undertake a top to bottom review and make fundamental changes to its entire organization. The outcome of this process was the transmission application, not a new business plan. It involved not a re-thinking of its capital plan to be more productive and to consider rate impacts as a central component, but simply a significant increase in proposed spending.

1.3.8 One would assume this new "commercial orientation" that Hydro One espoused during the oral hearing would have led to a focus on ensuring reasonable rates for customers. Mr. Vels testified that the new orientation includes the "need to be very focused on customer needs and preferences".[20] Yet Mr. Penstone, who was responsible for planning, said the "[t]he only direction that I received was take care, make sure we take care of the assets".[21]

1.3.9 In four months, it undertook an entirely new investment planning process to select potential candidate investments, optimize those potential investments, create from scratch a new model that looks at reliability risk (as opposed to reliability as requested from its board), develop and undertake a customer consultation process, in addition to meeting the new requirements of the transmission filing requirements. This all occurred without a Chief Operating Officer, who departed Hydro One in the middle of this process (February 2016).[22]

1.3.10 Hydro One undertook a customer engagement process, but that had its own serious problems. Moreover, it clearly was not meant to act as an input to the investment planning process. As Mr. Penstone explained, the customer consultation processes worked entirely parallel to the rest of the planning process.

> Okay, the optimization that you referred to was roughly in the middle of March. There were a number of parallel activities that were taking place, and I want to -- the investment planning process was one activity following one work stream. In parallel with that work stream was also the customer consultation process.[23]

[19] *Ibid*
[20] Tr.1, p.21
[21] Tr.8, 54
[22] *Ibid*, p.2
[23] Tr.6, p.60

1.3.11 Hydro One was not concerned with this because they had a "working assumption" regarding what their customers' expectations were from input outside the formal consultation.[24] This reflects the problems. The customer consultation, as flawed as it may have been, was designed to have little to no impact on the investment plan. This is inconsistent with the *Renewed Regulatory Framework for Electricity* ("RRFE") which makes customer consultation a central component to a utility's investment plan.

1.3.12 The rationale for the customer engagement process as part of a parallel process, not an integrated one, was the limited time it had to complete the planning process to be able to file its application for 2017 rates. In a similar vein, it chose not to do a third-party review of its transmission system plan, since there was "insufficient time".[25]

1.3.13 Hydro One's rationale for the rushed process and lack of a business plan was warranted due to the significant changes that were occurring within the company – most importantly the IPO and results of discussions with its new Board of Directors.[26] SEC agrees that fundamental changes such as new management team, Board of Directors, and change in ownership structure will result in changes to an organization and that may require a re-think of past processes and plans. The problem is that to meet the rate-setting cycle it still wanted to achieve, Hydro One hastily put together a transmission application that did not involve the necessary planning activities that are informed by a strategic vision and business plan. The interest of ratepayers protected through a proper planning process should not be secondary to Hydro One wanting its rates set on time.

1.3.14 While the transmission business plan approved by the Board of Directors in December of 2016 is essentially identical to the application, that appears to be out of strategic necessity in defending this application.[27] If the business plan was materially different, it would raise questions regarding the appropriateness of the application before the Board. In the seven months since the approval of the application, and the development of the first corporate wide business plan which was also approved on the same day, one would expect significant changes to have occurred. This is especially so considering it is the first application after the significant changes which supposedly required the re-think of the 2015 business plan.

[24] Tr.6, p.60-61
[25] I-1-8 (Staff IR #8)
[26] Argument-in-Chief, p.10-12
[27] K10.1

1.3.15 Undertaking a planning process for transmission alone, in early 2016 without the context of distribution which is normally set out in a corporate wide business plan, for example, as is now the case[28], is problematic. Hydro One, for rate-setting purposes, sets its transmission and distribution rates through separate applications historically in different years, but it is still one company that operates as a wholly integrated utility.[29]

1.3.16 The changes Hydro One made by changing its senior leadership, Board of Directors, and the IPO, were not external events it could not control. They were decisions that it felt were in it or its shareholders' best interest. The changes may very well lead to benefits to ratepayers in the long-run, but in the short-term they do not. The changes led to Hydro One creating an abbreviated planning process simply so that it could file a rate application in time for a 2017 rate change. It was not done in the interest of ratepayers. Ratepayers should not be the ones who suffer the consequences of Hydro One's incomplete and inadequate planning process. Hydro One's business planning process may now be "back on cycle and will remain so going forward"[30], but that it is not a reason for the Board to simply overlook the problems with the flawed process that is leading to significant increases in expenditures in 2017 and 2018.

1.3.17 The Board should make a number of reductions to the proposed revenue requirements as detailed in these submissions. Hydro One's planning process has led to a proposed investment plan that is inconsistent with its own evidence and RRFE's focus on proper planning, cautious improvement, and customer focused outcomes.

1.4 Summary of Position on Major Issues

1.4.1 ***Benchmarking and Metrics.*** Hydro One filed a benchmarking study from Navigant and First Quartile. SEC believes that, based on the evidence in this proceeding, the Board should conclude:

(a) ***Peer Group.*** 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) ***Gross Asset Value Metric.*** The normalizing metric – the denominator used to

[28] Tr.9, p.7; K10.1
[29] Tr.10, p.14; A-5-1, p.4
[30] Argument-in-Chief p.14

compare companies in the peer group – is gross asset value. In most normal industry scenarios, measuring performance based on gross asset value produces results that are the opposite of what better performance looks like. This is true where asset demographics are different between companies, and where companies have had poor cost control in the past. It also implies that spending more on capital today improves cost performance tomorrow, when the opposite should be true.

(c) ***Study Value***. The conclusions of the study with respect to Hydro One's current performance, and the use of the study in the future, are of no value to the Board. The study does not contain valid performance indicators that tie utility performance to outcomes valued by its customers. The performance indicators that it does include are flawed and provide no useful information.

1.4.2 ***Capital.*** Hydro One's significant increase in capital expenditures, specifically in the area of sustaining, is not justified by the evidence in this proceeding. In addition to serious concerns regarding its capital planning process, customer engagement, and the use of its reliability risk model, individual programs are not justified based on their condition and performance. Significant reductions are warranted. SEC proposes that the in-service addition equivalent of $156.13M in 2017 and $199.92M in 2018 in capital expenditures be disallowed. Further, the Board should disallow Hydro One's significant overspending in in-service additions from the 2015-2016 years to be added to rate base.

1.4.3 ***OM&A.*** While Hydro One's proposed OM&A for the test period is less than what has previously been approved, due to various adjuncts and their allocation, it masks the real picture of increased costs. The Board should make reductions to account for Hydro One's increasingly excess compensation levels compared to the market median. It should also make reductions due to the lack of productivity, increased costs as a result of the IPO, and the need to include the benefits of significant capital spending that is being proposed. SEC proposes the Board reduce Hydro One's OM&A by $23.9M in 2017 and $29.41M in 2018.

1.4.4 ***Tax Issues.*** The evidence in this proceeding does not produce a "right" answer for the issue of the deferred tax asset. SEC has identified four possible approaches the Board could take to this issue, but does not identify any of the four as our recommendation. Each of them would be reasonable, depending on the Board's view of the facts and the principles in play. The four

approaches are the following:

(a) ***The Hydro One Argument***. At its root, the argument by Hydro One applies the standalone principle and "benefits follow costs" to conclude that ratepayers should pay the notional tax amount in rates, and Hydro One should get to keep the differential. Properly characterized, it actually amounts to the ratepayers paying the departure tax over time in their rates, and to the issuance of shares to the Province being treated as an unrelated increase in the net value of Hydro One shares.

(b) ***Following RP-2004-0188.*** This characterization treats the departure tax and the issuance of shares as an economic net zero, equivalent to non-payment of the tax. Once it is accepted that the tax was effectively not paid, RP-2004-0188 makes clear that the ratepayers should only pay in rates the actual tax forecast to be paid. The utility should be able to recover in rates only its prudently incurred costs, plus a fair return. The actual tax cost is the prudently incurred cost.

(c) ***Distinguish Federal vs. Provincial Tax Impact.*** Under this characterization, the Board would recognize that the change from PILs to normal income tax causes the Province to lose some of their tax revenues, but not all of them. To the extent that the transactions result in a net revenue loss to the Province, that proportion of the deferred tax asset would accrue to the shareholder. The remainder of the deferred tax asset would accrue to the ratepayers. Thus, part of the annual tax expense would be included in rates (the federal component, which the Province is losing), and the rest would not. This would typically split the benefit 56.6% to the shareholder, and 43.4% to the ratepayers.

(d) ***Different Treatment of Liability vs. Asset.*** This characterization recognizes that part of the impact of the FMV bump is to recapture past tax timing differences (bringing the existing deferred tax liability to zero). The ratepayers got the benefit of those timing differences in previous years, and so should pay that part of the impact of the bump. The creation of the asset, however, is not the result of any past ratepayer benefit. Their benefit from that should come in the future, when tax is saved. In this scenario, the part of the annual tax expense that represents the future benefit would not be included in rates. The rest, reflecting the past tax savings ratepayers have

already received, would be included. This would split the benefit 64.6% to the shareholder, and 35.4% to the ratepayers.

2 BENCHMARKING AND METRICS

2.1 Introduction

2.1.1 The Applicant provided to the Board a report (the "Benchmarking Report") from Navigant Inc. and First Quartile purporting to demonstrate that Hydro One has good cost performance relative to its peers.[31] SEC believes it showed, during cross-examination of Mr. Grunfeld and Mr. Buckstaff, that the Benchmarking Report has no value to the Board in this proceeding. It is poorly conceived and executed, and like the customer engagement process of Hydro One, appears to have been designed to get the results Hydro One wanted, rather than real, objective information that would be useful to the Board.

2.1.2 Below, SEC summarizes two of the fundamental failings of the Benchmarking Report, and the implications of the expert evidence if it is accepted by the Board.

2.2 Approach of the Experts

2.2.1 SEC wishes to make a more general comment about this evidence. The witnesses, who appeared to want to answer "not necessarily" to even the simplest of principles applicable to their work, did not, in SEC's assessment, take sufficiently their obligation to be helpful to the Board. They apparently assumed that the members of the Board panel are benchmarking neophytes, and so would believe general statements that, while not directly untruthful, certainly were inconsistent with the considerable knowledge base that the Board has already developed about the subject.

2.2.2 One example of that is the notion that unit cost benchmarking does not have to seek a peer group of like companies. The Board has been through this particular subject in some depth during the process for developing the Renewed Regulatory Framework for Electricity, and predecessor processes, and consciously decided to use econometric benchmarking in order to reflect in a rigorous way the differences between the business conditions faced by electricity distributors. The Board had data on unit cost benchmarking, but elected to use the more complicated but rigorous econometric approach for the very reason that the distributors formed a diverse group.[32]

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[31] Ex. B2/2/1, Attach. 1.

[32] There is a useful description of the two types of benchmarking in Kaufmann, Lawrence F., "*Empirical Research in Support of Incentive Rate-Making in Ontario: Report to the Ontario Energy Board*", May, 2013, which ended up being the basis for the benchmarking structure in 4th Generation IRM and then in the RRFE. This built on work done by Dr. Kaufman's firm, Pacific Economics Group, in the 3rd Generation IRM process. In the Report, at chapters 5 and 7, Dr. Kaufmann describes the different approach taken when you are doing econometric vs. unit cost

This is because the Board had developed a deep knowledge of the strengths and weaknesses of unit cost vs. econometric benchmarking, enabling it to reach an informed conclusion on the best method for electricity distribution.

2.2.3 As discussed below, it may well be that unit cost benchmarking is an effective way of comparing Hydro One to its peers, and the more complex econometric approach was not needed. It is not the case, however, that a peer group is selected the same way in each case, and the witnesses should have known that. The fact that they avoided that question again and again, (although ultimately probably being forced to accept it), was indicative of their unhelpful approach to their responsibility to the Board.[33] Glib comments like *"Benchmarking is however you define it"*[34], in order to avoid dealing with the real issues, are also not helpful.

2.2.4 We believe that it would be useful for the Board, in its decision in this matter, to reiterate the nature of the obligation that experts bear when they appear before this Board. While they still report to their clients, their obligation once they enter the hearing process is to be independent and objective, rather than being advocates for their clients.[35] An expert who seeks to "stay on message" is not meeting that obligation.

2.3 The Peer Group

2.3.1 The Benchmarking Study compares the performance of Hydro One Transmission to a peer group of fifteen other transmitters. The peer group is a group of transmitters that are not very similar to Hydro One, a fact that was not immediately apparent from the pre-filed evidence, or from the responses to interrogatories.

2.3.2 In the pre-filed evidence, Hydro One filed the stakeholdering materials[36], and in the presentation

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benchmarking. In the former, differences between the companies are used as data to produce a mathematical relationship between business conditions/company characteristics, and cost. (This is what is being used in the RRFE today.) In the latter, differences between the companies are used to create peer groups of similar companies that can be compared fairly one to the other, precisely because they are similar. The method used in this proceeding is the unit cost benchmarking approach, and the resistance of the experts to the basic principle that the companies in the peer group should be as similar as possible is, frankly, inexplicable.

[33] Similarly unhelpful was the attempt to avoid admitting that econometric benchmarking, unlike unit cost benchmarking, needs a diverse comparator group. See Tr.3, p. 17-18, where they eventually admitted that a diverse group is required for econometric benchmarking.

[34] Tr.3, p.17

[35] See *Acknowledgement of the Expert's Duty*, Form A to the Ontario Energy Board, *Rules of Practice and Procedure*

[36] Ex. B2/2/1, Attach 2. The relevant material is page 33 of the Navigant/First Quartile presentation.

the experts listed the characteristics that should be used to determine the peer group. For example, they proposed that the peer group should be the "same relative size", as determined by a number of factors, plus similar geography and weather, similar organizational structure (public vs. private, union vs. non-union), and similar system design, for which they used the example of voltage levels.

2.3.3 The Benchmarking Report, on the other hand, lists the peer group selected in Figure 33[37], including Hydro One, but then only shows certain size-related comparators.

2.3.4 SEC followed up on this in Interrogatory I-6-43, and asked for a table showing the whole group, but with their data for all of the comparator characteristics. The response provided that table, but omitted Hydro One from it (unlike Figure 33 in the actual report). It also omitted the comparison based on voltage differences.

2.3.5 SEC followed up on these points in the oral hearing.

2.3.6 ***Voltage Differences.*** On the question of voltages, the experts apparently admitted that voltage levels of transmission can be a material factor in transmission assets and costs.[38] However, they did not adjust for voltage in either selecting the peer group, or choosing the comparators. They tried to say instead that cost of the assets covers this difference, but then backed off that statement. The exchange is enlightening[39]:

> MR. SHEPHERD: So there are other factors you could use, like line length or peak megawatts or throughput. There is a bunch of them; right?
> MR. BUCKSTAFF: There is several of them.
> MR. SHEPHERD: And you chose gross asset value.
> MR. BUCKSTAFF: Yes.
> MR. SHEPHERD: Right? Did you adjust for voltages in the gross asset value?
> MR. BUCKSTAFF: No.
> MR. SHEPHERD: Well, wouldn't that have a significant effect on the cost ratios? If you have a gross asset value that's based on high-voltage system, that's going to have much higher cost than a low-voltage system; right?
> MR. BUCKSTAFF: Not necessarily. If you build ten miles of 500 KV line or 500 miles of 69 KV line, which is going to be more expensive?
> MR. SHEPHERD: I see, I see, so you'd have to adjust for line length as well.
> MR. BUCKSTAFF: That's why asset value is such a good normalizer. It accommodates both.

[37] Benchmarking Report, Appendix A.
[38] Tr.3, p.27; This makes sense, since it was on their original list of desired similarities between the members of the peer group.
[39] Tr.3, p.27-28

> MR. SHEPHERD: I see. So two utilities with the same asset value, but one with 10 percent the length, should have similar costs?
> MR. BUCKSTAFF: They might.
> MR. SHEPHERD: Well, no, would you expect them to?
> MR. BUCKSTAFF: Not necessarily. I mean, there is a variety of factors, and voltage is one. But there is a multitude of factors that make a difference.

2.3.7 It appears that the only reason voltage was eliminated as a factor was that the information was more difficult to obtain.[40] The fact that it was excluded, however, was neither referred to nor explained in the answer to SEC IR #43.[41]

2.3.8 ***Hydro One Is an Outlier***. The second problem with SEC IR #43 was that it did not include Hydro One. After the hearing, in Undertaking J3.4, the experts finally provided the table including Hydro One – although still not including voltage differences.

2.3.9 What Undertaking J3.4 shows, and what was clear even during the discussion in the oral hearing, is that Hydro One is not similar to the other members of the peer group. On virtually every single one of the size metrics – gross asset value, service territory, km. of lines, Mwh transmitted – Hydro One is larger than any of the other companies in the group, in several cases by orders of magnitude. Even in the case of customers served, the experts used a metric – direct distribution customers of the respective transmitters – that reduces the number of customers assumed for Hydro One. When all distribution customers Hydro One feeds with its transmission are included, it would also be the largest, although approximately the same size as SoCalEd.[42]

2.3.10 While resisting the notion that Hydro One is an outlier, the experts did agree that it was, at least on their chosen factor of gross asset value, in the following exchange[43]:

> MR. SHEPHERD: So we asked you, why is gross asset value the right way of doing this, and if you turn to page 8 of our materials, in your study at page 35 -- that's why I said you should have it in front of you -- you said here's why gross asset value is the right way to do it, and you showed the fit of your group; right? Your comparator group.
> MR. BUCKSTAFF: Yes.

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[40] Although they did admit to having the data: Tr.3, p.26.
[41] I-6-43 (SEC IR#43)
[42] We note that SoCalEd might also have a larger number of ultimate distribution customers, and so might some of the others, so this metric of distribution customers may not, on the data before the Board, be a fair reflection of the size of the transmission companies. We note, however, that in B2/2/1, Attach 2, page 33, the metric proposed by the experts was "Number of Transmission customers, i.e. LDCs, large customers", which we were not able to find referred to anywhere after that.
[43] Tr.,3 p.28

> MR. SHEPHERD: But what you didn't have on it was Hydro One, so then we asked you, put Hydro One on it, please, and page 8 is where Hydro One shows up. Hydro One is an outlier on gross asset value; isn't it?
> MR. BUCKSTAFF: Um-hmm.

2.3.11 A similar admission arose at another point, where after counsel for SEC went through the various size-related criteria the experts had said were relevant, they had the following exchange[44]:

> MR. SHEPHERD: … So I am not sure I understand how Hydro One is comparable to this group of companies. They are an outlier on almost everything.
> MR. BUCKSTAFF: They are an outlier -- and I say an outlier. They are larger that many of the others, that's accurate.

2.3.12 Perhaps more important, after some difficulty, they admitted that being an outlier is not a good thing in these studies, represented in the following exchange[45]:

> MR. SHEPHERD: Yes, thanks. So you will agree, won't you, that if entity that you are trying to benchmark is dissimilar from the comparators, is an outlier, then your comparison is probably not as good? That's at least true, right?
> MR. BUCKSTAFF: It makes it harder, yes.

2.3.13 ***There Are No Economies of Scale.*** The reason the experts used to justify the selection of such a diverse peer group was that, in their view, economies of scale are not material in transmission companies of this size range.

2.3.14 Pressed on this, Mr. Buckstaff was not willing to say categorically that there would be no economies of scale difference between the smallest and largest companies in the peer group[46], but he continued to insist that all of the utilities in the peer group are "big enough".

2.3.15 However, when asked for support for that statement, Mr. Buckstaff was unwilling to provide any. The support, he said, came from secret studies his firm has done, which he can't share with the Board. That led to the following instructive exchange[47]:

> MR. SHEPHERD: And you in fact say in that same response, "In the work we have done around this over the years, we have not found that the bigger utilities are more efficient than smaller ones," right?
> MR. BUCKSTAFF: Correct.
> MR. SHEPHERD: Okay. So then we asked you do you have empirical data on that. And if you take a look at page 12 of our materials, your answer is, sorry, we are not going to tell you what our data is. How are we supposed to rely on your opinion, if you

[44] Tr.3, p.23
[45] Tr.3, p.20
[46] Tr.3, p.32
[47] Tr.3, p.32-33

won't show us your data? Do you have empirical back-up for that statement that there are no economies of scale above that size?
MR. BUCKSTAFF: In terms of individual studies that we have done, yes. In terms of things that are publicly available, no.
MR. SHEPHERD: So then how is the Board supposed to conclude whether you are right or not, if they can't see your work? Just take your word for it?
MR. BUCKSTAFF: That would be nice.

2.3.16 As discussed later, the implications of this study, and the metrics used, the use of gross asset value to adjust for scale has a number of problems. One of them is the implicit assumption that the relationship between the costs to run the utility, and the value of its assets (i.e. size of the utility, in this context), is linear, something they admit.[48] If gross assets increase by 10%, then all manner of operating and capital costs should also go up by 10%. If they go up by less, that utility is performing better, and if they go up by more, that utility is performing worse.

2.3.17 It is certainly possible that economies of scale cease to exist at a certain size for transmission companies. However, SEC submits that, if the experts want to base their entire study on that assumption, it would be appropriate, and helpful to the Board, to provide some backup for that statement. That is particularly true where, as here, the experts were told during the stakeholdering process that this assumption was an issue of concern to the customer groups. What, after all, is the point of stakeholdering if the experts simply ignore the concerns raised that turn out to be inconvenient?

2.3.18 ***Best Practices.*** The real reason that the experts did not choose a peer group of similar companies is that they also added another goal to the Benchmarking Study: recommendations of best practices Hydro One should follow. While not admitting that this was the only reason for an overly diverse peer group, they did admit it was one of the reasons.[49]

2.3.19 The sad thing here is that, when it came time to recommend best practices, the actual benchmarking analysis, and the data from the peer group, was almost entirely ignored.

2.3.20 The starting point on this was SEC interrogatory #42(i)[50], which asked the experts to track the connection between the data from the study, and each recommendation. They were unable to do

[48] Tr.3, p.31
[49] Tr.3, p.30, 39
[50] I-6-42(i) (SEC IR #42)

so, and instead emphasized that their best practices recommendations to Hydro One "were based on a balanced view of Hydro One costs and other operating performance factors as well as ***drawing on the deep experience of the experts***" [emphasis added]. There is no mention of the peer group or the study data.

2.3.21 During the course of a discussion with the experts in the oral hearing[51], counsel for SEC then elicited from them the information that a lot of their best practices were the result of discussions with Hydro One staff. The experts heard in those discussions that Hydro One is not doing something; they know from their past dealings that other utilities do that, so they recommend it. There would appear to be little connection between the study data and the recommendations. As Mr. Grunfeld said, "...not everything has a straight line between A and B".

2.3.22 What this means, though, is that while one of the reasons for the diverse peer group was to identify best practices, it turns out that particular goal was not achieved. Or, put another way, if the peer group had been a more similar group of utilities, the best practices recommendations would have been virtually the same.

2.3.23 ***Conclusion.*** SEC believes that, even if unit cost benchmarking was the best way to compare transmission companies (a subject that was not pursued in this proceeding), the peer group selected did not produce a proper comparison of Hydro One to its real peers. Whether this could have been improved by a better peer group, or by using econometric benchmarking instead, is not apparent from the record. What is apparent is that the comparison to this group of transmitters is not helpful to the Board.[52]

2.4 The Denominator of the Metric

2.4.1 Despite the problems with the peer group, it is the problems with the metric selected that are really significant. Essentially all of the metrics used by the experts to compare Hydro One to the

[51] Tr.3, p.39-45

[52] SEC notes that this only hit the highlights of the problems with the peer group. By way of example, many of these companies are integrated generation and transmission (and distribution, in some cases) utilities, with much different cost drivers than Hydro One. As well, although age of assets is known to be an important factor in transmission costs – see Tr.3, p.34-35 – and the experts had some asset demographics information, no adjustments were made for this. There are a number of other, similar problems.

peer group had as their denominator gross asset value.[53] The intent was to use gross asset value to normalize for size of utility[54], because the companies in the peer group were different sizes. While, as noted earlier, that doesn't pick up economies of scale, it does pick up the raw difference between Utility A, and Utility B that is half its size.

2.4.2 The problem with using gross asset value is that all performance is driven by how expensive is your system. Costs at a given $ amount are better performance if you have a more expensive system, and worse performance if you have a less expensive system. At no time did the experts explain how this supposed relationship can be justified.

2.4.3 ***The Problem of Age***. Older systems will have a lower gross asset value, because the original cost of the assets was incurred years ago, when costs were lower. Someone who has an older system should be spending more, both on operating costs, and on capital renewal. However, when you normalize using gross asset value, you conclude that the company with an older system is a poor performer relative to its peers.

2.4.4 Conversely, if a transmitter has gone through a recent building boom, so their system is generally fairly new, their gross asset value will be very high. This means, for them to perform as well as their peers, they can spend a lot more each year on operating and capital costs. In the real world, that is not the case. In the real world, the company with the new system should be spending less on a unit basis than its peers, because the equipment needs less maintenance, and because the amount of capital replacements required should be lower.

2.4.5 A simple example shows that. Utility A has a $1 million station that it built 30 years ago. It already has to replace some of its components, and will have to replace the whole thing in a few years. Capex on the station is $50,000 this year. Meanwhile, the costs to operate that station are fairly high, $50,000 this year. Not only is it in worse condition, but the technology built into the station is less sophisticated, and more in need of TLC. Utility B just built a similar-sized station, at today's $2 million cost. That station does the same work, but there is no capital spending

[53] Tr.3, p.38
[54] Tr.3, p.30

needed on that station this year, and only $20,000 of operating costs.[55]

2.4.6 If Utility A has 10% ratio of Opex+Capex/Gross Asset Value, and Utility B has a 1% ratio of Opex+Capex/Gross Asset Value, they are actually equivalent performers. However, when normalized using the Navigant/First Quartile approach, Utility B is ten times better than Utility A. In fact, Utility B could spend $200,000 on their station, and still be judged as having equivalent performance to Utility A.

2.4.7 Economists (and financial analysts, and engineers, and many others) use the term "sanity check" to describe testing an analytical conclusion against the real world. In this case, the simplest of sanity checks shows that the gross asset value approach produces not just an inexact result, but a result that is the opposite of what it should produce.

2.4.8 ***The Problem of Gold-Plating.*** Even if assets are all of the same age, one utility may have better cost control on their capital projects than the other. If Utility A and Utility B, each put in the same station five years ago, and have the same annual costs for that station today, common sense says that they should be considered comparable performers.

2.4.9 However, if Utility A spent $2 million on that station, and Utility B spent $2.5 million, because it doesn't control capital spending as well, Utility B will look like a better performer this year than Utility A. In fact, again the opposite is true. Using gross asset value as the denominator in normalizing comparisons is the reason for this incorrect result.

2.4.10 ***Time Series Comparisons.*** The biggest problem with this, though, is seen when a transmission utility embarks on a period of increasing capital expenditures, as Hydro One proposes to do now. Each year that the utility replaces old assets with new, its gross asset value goes up.

2.4.11 Under the approach proposed by the experts, the annual costs of that utility should also go up by the same percentage, in order to maintain the same level of performance. If the cost of the asset doubles because it is new, the operating costs to run it should double, and so should the capital to

[55] Interestingly, the cost of the two stations for regulatory purposes is probably similar. Although the Opex plus Capex is higher for the older station, the rate base is much lower too. When you add that cost in, the two stations may have broadly similar total costs to be included in rates.

replace it or its component parts.

2.4.12 What actually happens in that case? Well, in fact, with newer assets the utility should be able to drive down some operating costs. Newer costs have better technology, and are less prone to breaking, and need less maintenance. Also, with newer assets, the utility should have fewer old assets to replace, so annual capex should go down (at least, over time).

2.4.13 In the case of Hydro One, this means that, if the capital budget requested is approved, Hydro One will show improving performance on all of the Navigant/First Quartile metrics without ever having to reduce their costs. This is not just a question of better performance without being more efficient. It is worse than that. Hydro One, on this scenario, does not even need to get the operating and capital savings that naturally flow from having spent more on the system. They can become less efficient, and as long as they are spending money to build new infrastructure, they will be considered to be improving in their efficiency.

2.4.14 ***Conclusion – Don't Forget the Customers.*** Gross Asset Value is not a reasonable denominator to use, either to normalize companies in a peer group for size, or to keep score as to whether a company's performance is improving over time.

2.4.15 The primary reason for this is that the metric being used is not an "outcome" that the customers value. Ratepayers do not want them to increase their gross asset value. That is not a goal of benefit to them.

2.4.16 Contrast that with a denominator (to normalize for size) based on system capacity, or throughput, or similar non-dollar metrics. Customers value those things. When you increase the capacity of the system, you are doing so to provide more service to the customers. When you increase the throughput, it is because the customers sought and received more electricity delivered to them. These are outcomes customers should pay for. These are outcomes that justify increasing annual costs. Ratepayers are getting something for it. Gross asset value is not such an outcome. Justifying increasing costs by reference to increasing gross asset value is just asking the customers to pay twice. It measures no cost differential that is of relevance to what the customers are receiving for their money.

2.5 Summary

2.5.1 SEC therefore recommends that the Board give no weight to the Benchmarking Report. SEC submits that the experts selected an inappropriate peer group to compare to Hydro One, and then fashioned metrics for comparison that do not disclose the real performance of the company. Indeed, they appear to produce performance results that are the opposite of what common sense would expect.

3 CAPITAL

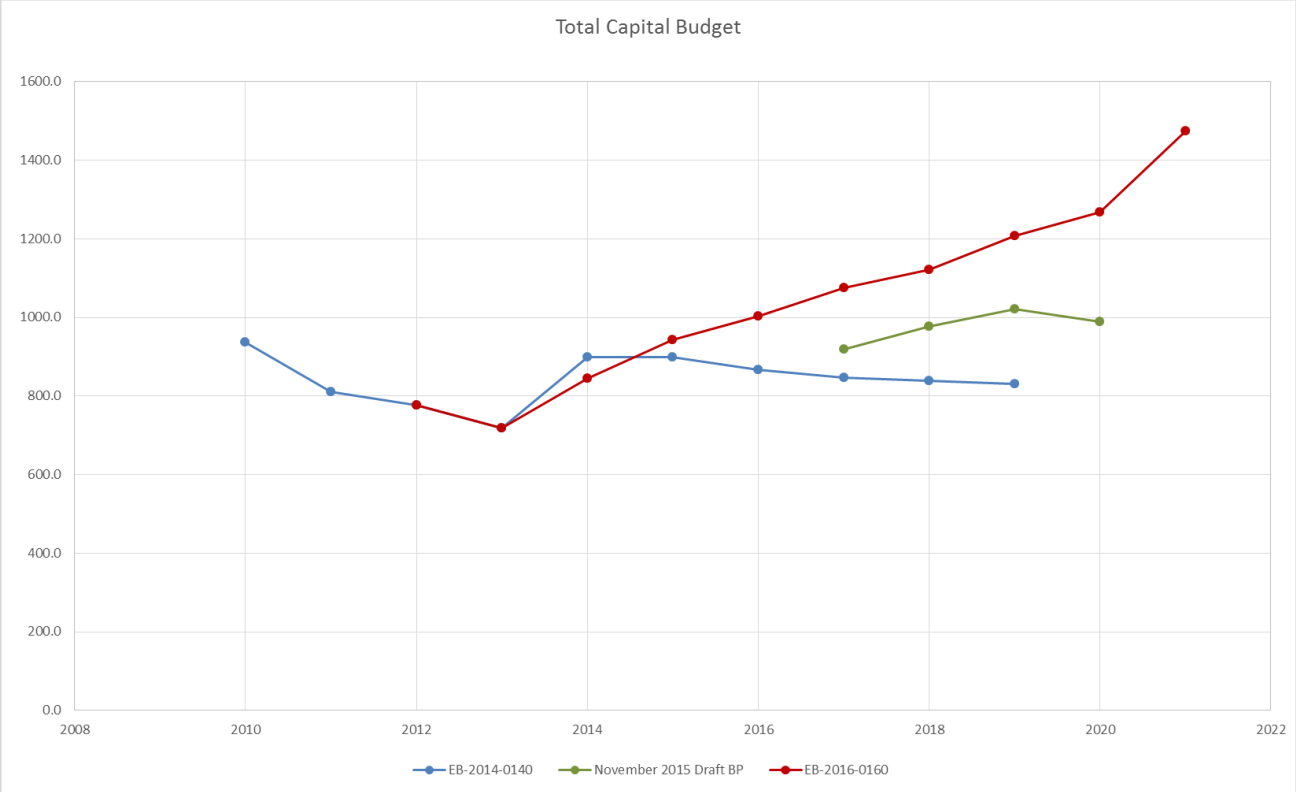
3.1 Overview

3.1.1 Hydro One is proposing to spend $2.2B on capital during the test period.[56] This represents an increase of $433M (25%) in total transmission capital spending over what was approved in the last application for the 2015 and 2016 test years.[57] The single largest category of spending is $1.6B for sustaining capital. Hydro One is proposing an increase of $488M (43%) over what was approved in the last application for the previous test period for this category of spending.[58]

Total Transmission Capital $M)	2015	2016	2017	2018	2015-16	2017-2018
EB-2014-0140	899.4	866.3	847.8	838.8	1765.7	1686.6
November 2015 Draft BP			920	978		1898.0
EB-2016-0160	943.0	1003.8	1076.1	1122.2	1946.8	2198.3
Total Sustaining Capital (@M)	**2015**	**2016**	**2017**	**2018**	**2015-16**	**2017-2018**
EB-2014-0140	581.9	548.6	597.4	636.7	1130.5	1234.1
November 2015 Draft BP			650.0	731.0		1381.0
EB-2016-0160	694.3	724.3	776.8	842.1	1418.6	1618.9
Source J8.1, Attachment 2						

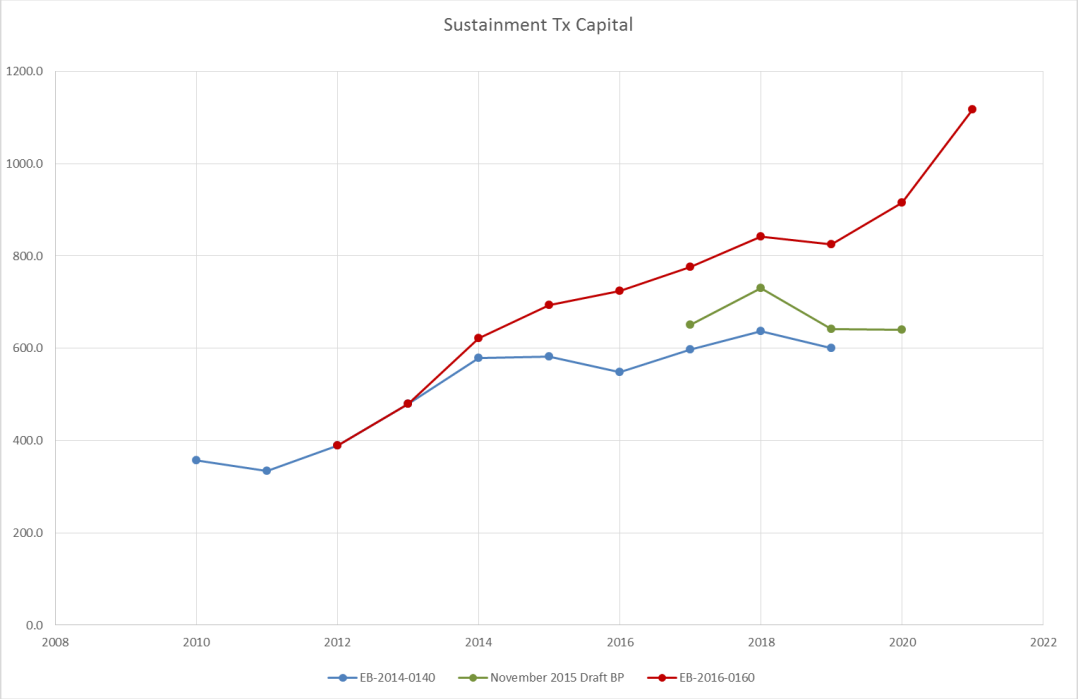
3.1.2 Not only is Hydro One proposing significant increases in capital expenditures as compared to its previous applications, but also compared to its previous forecasts for what it would require in 2017 and 2018. In its last application, Hydro One provided a similar longer-term forecast as it has with this application, and forecasted $1.69B in total transmission capital expenditures; of that $1.2B would be for sustaining work.[59] The proposed investment plan in this application represents an increase of $511M (30%) and $384M (31%) respectively.[60]

[56] A-3-1, p.13
[57] EB-2014-0140, A-16-8, p.3 (K1.2, p.9)
[58] *Ibid*
[59] *Ibid*
[60] *Ibid*

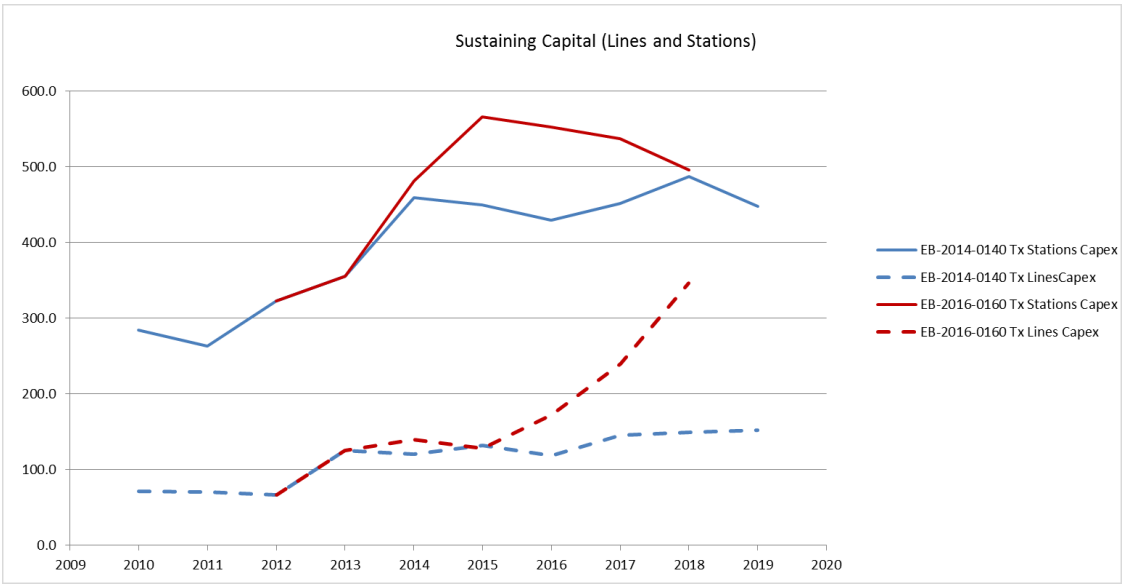


3.1.3 Most troubling is the longer term forecast for transmission capital spending. Both the 2015-16 rates application and the aborted November 2015 draft business plan forecast the flattening out of capital spending past this rate application. Now, Hydro One's capital investment forecast has its spending dramatically increase past the test periods at issue in this proceeding.

3.1.4 The major driver of the capital spending is the sustaining category which represents almost 75% of the total capital expenditures. As discussed in detail below, SEC submits the capital investment plans, primarily the proposed sustaining capital, are unreasonable and unjustified. Hydro One has not justified the need for such a large capital program considering its strong reliability, end-use customer preferences for lower rates, significant problems with the Reliability Risk model, insufficient justification for many of its individual capital programs, and a lack of productivity built into the capital spending program itself.



3.1.5 Within sustaining capital, Hydro One has broken down its expenditures into two major categories, lines and stations.[61] The biggest change as compared to the forecast provided in EB-2014-0140 is in the lines category where Hydro One is now proposing to spend a significant amount more than it had originally proposed.[62]



[61] See for example, B1-3-1, Attach 1

3.1.6 While SEC has significant problems with Hydro One's independent benchmarking evidence, what it does show is that Hydro One may look average on a total capital expenditure basis[63], as of 2014 (the year the benchmarking information comes from), they are in the bottom quartile for both lines and substation sustaining capex per asset compared to Navigant's selected peer group.[64] Considering its spending has only increased since 2014, SEC would expect that it remains in the bottom quartile and is likely getting worse.

3.2 Reliability

3.2.1 With the significant increase in capital expenditures, specifically in the sustaining category, one would assume that Hydro One's reliability was poor and that it required these system upgrades to reach an acceptable level of performance. Yet, the evidence in this proceeding demonstrates Hydro One's system is one of the most reliable in the country and is in fact improving, not getting worse.

3.2.2 Hydro One's reliability performance has been consistent or improved over time, and compared to the Canadian Electricity Association ("CEA") benchmarks, is significantly better on each of the major multi-circuit system metrics. Hydro One's performance compared to the CEA composite benchmark has been and continues to be better on SAIDI, SAIFI and the delivery point unreliability index.[65] In fact, with respect to SAIDI (interruption duration), Hydro One has been in the top quartile, and has been so on average since 2006.[66]

3.2.3 Hydro One's response to this inherent contradiction has been that these reliability statistics[67] and reliability more generally, are lagging indicators[68] and that equipment performance provides a leading indicator of reliability.[69] At a high-level, SEC does not dispute that equipment performance is a leading indicator of system reliability, as the more equipment fails, the more likely there are system interruptions. Where SEC does disagree is Hydro One's contention that system equipment outages should be the main focus on the level of sustaining investment. The relationship between equipment outages (i.e. performance) and reliability is very complex, especially in a system where a significant portion is multi-circuited. Even in Hydro One's single

[63] B2-1-1
[64] J3.3
[65] B1-1-3, p.24-25
[66] J2.4
[67] Tr.1, p.71; Argument-in-Chief, p.30
[68] Tr.5, p.108
[69] Tr.5, p.112; B1-1-3, p.26-27

circuit system, a failure of one piece of equipment does not mean that there is an interruption or that an interruption is necessarily that much more likely. The relationship is very complex and it does not appear Hydro One has much more than a general sense of it.

3.2.4 A good indicator of the difficulty in using system performance as a leading indicator is the relationship between unplanned outage hours due to requirement failure and total interruption hours. The ratio is miniscule and is getting smaller as time goes on. In 2015, Hydro One had 272,000 hours of unplanned equipment outages due to their failures, yet only had 658 total hours of system interruptions. Put it another way, in 2015, for every 100 hours of total equipment outages due to their failure (i.e. their performance), there were 24 minutes of system interruptions (i.e. no power at a delivery point). This ratio has been steadily decreasing over the last few years.

Unplanned Outage Hours Due to Equipment Failure to Interuption Hours Ratio						
	2011	2012	2013	2014	2015	
Unplanned Outage Hours Due to Eq Failure	**165000**	**205000**	**170000**	**194000**	**272000**	**(1)**
Total Interruptation Hours	**1873**	**1064**	**973**	**551**	**658**	**(2)**
Ratio	**1.14%**	**0.52%**	**0.57%**	**0.28%**	**0.24%**	
Source: (1) B1-2-2, Attach 2, p.15; (2) J7.4						

3.2.5 Ratepayers are concerned with system reliability, not equipment performance. They care when they flip the switch and the power will not come on, not if a specific piece of equipment that makes up the large transmission system is not working. With the relationship between these two things so complex, the Board should not allow Hydro One to over-rely on equipment performance as a driver of sustaining capital spending, as they have done in this application. Hydro One's reliability performance on its existing capital budget demonstrates that it is getting the big stuff right in its asset management. It does not need more ratepayer funds to go towards increasing capital expenditures.

3.3 Customer Engagement

3.3.1 In meeting the requirements under the RRFE, Hydro One undertook some customer engagement activities with respect to its proposed capital plan. These customer engagement activities facilitated by Ipsos Public Affairs (IPSOS) are fundamentally flawed and should not be relied upon by the Board. They appear intended to confirm Hydro One's proposals. As one online participant aptly put it, "[i]t sounds like you are asking me to justify a rate increase".[70]

[70] J4.7, Attachment 1, p.2

3.3.2 Hydro One presented multiple spending scenarios to the customers that were consulted, and the report indicated that they opted for a spending level between scenario 2 (medium) and 3 (the largest).[71] The information provided to participants was misleading, hard to understand, and not provided in the proper context. Most troubling is that the customers from whom Hydro One sought feedback represent only a very small subset of those who will ultimately be responsible for their proposed rate increase.

3.3.3 ***Proper Context and Information Not Provided.*** In each of its in-person and online waves, Hydro One provided a presentation to participants.[72] That presentation included background information before the investment scenarios were provided for feedback. Hydro One provided background information on its system, including about system reliability, equipment performance, t, assets beyond expected service life, and reliability risk.[73] At no point did Hydro One provide the proper context for any of this information. It did not provide information regarding Hydro One's reliability as compared to its peers. It did not show them the CEA benchmarking information that it has including its status in the in the top quartile. Nor did it provide information regarding its own inability to correlate reliability risk and reliability, and how new and untested the reliability

3.3.4 risk model was.[74] This information would be central to understanding what the data meant.

3.3.5 In its presentation to customers in the engagement, Hydro One says that "transmission reliability remains flat."[75] Yet the information provided in its proposed scorecard states that reliability is improving.[76] The reason for this difference is that Hydro One, for the purposes of presentation to customers, uses the last 10 years of data, and the scorecard uses 5 years of past data.[77] Hydro One did not provide any good reason for the change, simply stating that it was a management decision.[78] The rationale is easy to understand; it tells a better story when seeking customer's approval or acquiescence for increased capital spending.

3.3.6 When Hydro One moved on to explaining the three spending scenarios, it did not provide any

[71] B1-2-2, Attachment 1, p.23
[72] B1-2-2, Attachment 2, p.1-16; Tr.3, p.177
[73] *Ibid*
[74] Tr.1, p.176
[75] B1-2-2, Attachment 2, p.9
[76] Tr.3, p,187
[77] Tr.3, p,188
[78] Tr.3, p,187-188

information on the amount of capital spending that had been approved in the past.[79] Nor did it provide any information about how Hydro One had dramatically changed its capital spending plans from what it had proposed in 2014 or 2015. Providing the entire context of proposed spending is important in shaping customers' views about the appropriateness of it. If those who took part in the engagement process knew that Hydro One was proposing to increase its sustaining spending by double digits from historical levels, for a utility whose reliability is already in the top quartile, it is reasonable to expect their responses would have been very different.

3.3.7 Further, the customer engagement process was centered on how different spending scenarios affected reliability risk. It was the concept that underpinned the consultation process.[80] While IPSOS says that most customers said they understood the concept[81], SEC is skeptical that they actually did. Reliability risk is not an easy concept to understand. This was clear from the amount of time that was taken up during the oral hearing discussing it. They likely thought they understood the concept, or at the very least were not willing to admit they did not in such a public setting.

3.3.8 ***Consultation Not Representative of Those Who Will Pay Hydro One's Tx Rates.*** The most problematic aspect of the customer engagement is that it is only representative of a subset of those who will ultimately bear the increase in transmission rates. Hydro One's customer engagement process was with customers as defined by the transmission code, i.e. customers who are directly connected to its system. Those customers include only a few end-use customers, generally large industrial ratepayers. The rest are local distribution companies ("LDC") and generators. LDCs pass on transmission costs to their end-use customers, and generators only pay transmission rates if they use the system to export electricity out of Ontario.[82]

3.3.9 Since 92% of Hydro One transmission revenue will be collected from LDCs, who pass the cost on to their end-users, only 8% of revenue could have been represented in the consultations.[83] And those end-use customers, largely very large industrial businesses, may have very different needs and preferences than residential, commercial, or institutional end-use customers, such as schools.

[79] Ibid, , B1-2-2, Attachment 2, p.17-23
[80] Tr.3, p.175
[81] Tr.4, p.120
[82] These generators pay the Export Transmission Rate for which no change is being proposed in this application.
[83] J1.1; Tr.4, p.54

Industrial customers are generally much more sensitive to reliability issues, even momentary ones.

3.3.10 When confronted with this fact during the oral hearing, Hydro One claimed that the LDCs said they were representing the views of their customers in the consultation.[84] SEC disagrees that LDCs can be considered the voice of end-use customers for the purposes of this consultation. While they may have said in consultation at a general level that end-use customers are concerned with rates, they have their own applications to consider. Many of them have, are, or will be seeking rate increases in the future.

3.3.11 The best evidence of the difference between what Hydro One's definition of transmission customers' preferences are, as compared to distribution customers who are end-use transmission customers, is that of Hydro One's own distribution customers. Hydro One's consolidated business plan succinctly describes the difference:

> Transmission customers' top priority was reliability maintenance or improvement and they were willing to accept a small rate increase to achieve that outcome. In addition, energy quality was a significant factor for several sophisticated energy users. Distribution customers consistently prioritized low cost and wanted Hydro One to do its best to limit increases in rates. These preferences have guided the development of the investment plan for each business, with Transmission focusing on investments that will improve reliability and quality, and the Distribution investment plan designed to leverage productivity and keep rate impact low while still seeking some improvements in reliability. [85]

3.3.12 Hydro One's distribution customers, who would have similar preferences as all other end-use customers of LDCs, prioritize low rates above all else, while transmission customers' top priority was reliability, maintenance and improvement. SEC submits if LDCs' end-use customers had taken part in the consultation, which represents 92% of those who will pay Hydro One's transmission revenue requirement, one can easily expect the feedback to be very different. Consistent with their views on distribution services, they would have told Hydro One that their top priority is keeping rates as low as possible.

3.3.13 Hydro One's rationale for including only directly connected customers in their consultation is that it is those customers it has a direct relationship with and customers of other LDCs would be

[84] Tr.4, p.54; Even Hydro One did know if LDCs actually represented the views of their end-use customers. (See Tr.11, p.91).
[85] K10.1, Hydro One Consolidated Business Plan 2017-2022, p.3

confused.[86] SEC submits that there is logic in this view but what that means is that the customer feedback is not reflective of those who will ultimately bear the impact of the rate changes. Since Hydro One never tested engaging with end-use customers of LDCs who pay their rates, we will never know if there was sufficient confusion so as not to think it was meaningful to engage with them at all. Most concerning to SEC is that Hydro One did not even use the information it had from its own distribution customers regarding their preferences for lower rates, to inform their transmission application.

3.3.14 After being confronted with the flaws of its customer consultation activities, Mr. Griffen, on behalf of IPSOS, appeared to try to walk back the significance of the engagement and the resulting report from it by implying that it really was not that important and really was only qualitative in nature. As he described it, "[t]he essential report is a giant footnote, for lack of a better term."[87] SEC agrees. The report is not quantitative at all. Even for the small subset of customers represented, there were differing numbers of participants representing each customer making the data unrepresentative of even that group.[88]

3.3.15 For the customers who were represented, the consultation does not provide an accurate or useful enough picture of their preferences to have an effect on Hydro One's investment plan. It appears the results of the investment plan were simply used to confirm their proposed spending plans. The consultation took place in the winter of 2016, with the draft report from ISPOS provided to Hydro One on March 29th and the final version provided on April 18th.[89] This was just over a month before the proposed plan was approved by Hydro One's Board of Directors on May 6th.[90] In fact, Hydro One's CEO and CFO reviewed the investment plan on April 12th, before the final report was even submitted.[91]

3.4 Reliability Risk Model

3.4.1 Hydro One has attempted to bolster its capital plan through the introduction of the Risk Reliability model. This model seeks to measure and thus demonstrate how changes to capital spending affect the *risk* of unreliability. This new model, which was developed only months before the filing of the application, was a central component to the customer engagement process

[86] I-6-13 (SEC IR #13)
[87] Tr.4, p.16
[88] B1-2-2, Attachment 2, p.11
[89] J8.1 Attach 1, p.2
[90] *Ibid*
[91] *Ibid*

Hydro One undertook, and the justification for need of the proposed capital spending. SEC submits the Board should place little weight on the model. It is untested, flawed, and misrepresents the actual changes in reliability risk as a result of the proposed capital spending.

3.4.2 The Reliability Risk model uses hazard curve information derived, for a subset of Hydro One's asset categories, to determine the probabilistic determinations of the failure risk of the entire asset based on age demographics of the assets measured.[92] Hydro One then adjusts the demographic profile of those assets based on its proposed capital plan and compares the new overall failure risk to determine the change in relative risk.[93]

3.4.3 Hydro One has categorized the reliability risk into three asset categories: lines, transformers and breakers, which it claims represent 84% of its total interruptions by duration. Based on its model, and weighted by interruption duration, the Hydro One view is that its proposed capital plan will have the effect of reduced reliability risk of 2% by the end of the test period. [94]

3.4.4 There are a number of problems with Hydro One's model and how it is presented in the evidence to justify the capital spending proposals.

(a) ***No Investment Scenario Unrealistic.*** Throughout the evidence, Hydro One has shown the results of the reliability risk model calculations, comparing the change in risk by the end of the test period after the proposed capital expenditures (investment plan), and without the proposed investments (-2% versus 10%).[95] At first glance it would be fair to assume this shows the difference between the proposed investment plan and one based on historical spending. But what it actually shows is the difference between the proposed plan and one where no expenditures are being made to replace existing assets. This is an entirely unrealistic scenario. No party would ever realistically suggest that Hydro One undertake no sustaining investment over the test period. The scenario should be completely excluded as it does not provide any realistic information and creates the impression that there is a false choice: approve the proposed investment plan and decrease reliability risk, or spend no money and see a very significant increase.

[92] I-1-15 1 (Board Staff IR #15)
[93] Staff IR 15
[94] B1-2-4, p.8
[95] See A-3-1, p.7; B1-2-4, p.8

(b) ***Many Major Asset Categories Not Included.*** Many major asset categories were not included in the model, although based on the category descriptions, should probably have been. While Hydro One uses the term 'lines' as a category, and allocates 69% of the interruption duration to the category for the purposes of the aggregate calculation, the underlying data used in the model is not for all of lines equipment but just 1of at least 8 asset categories that comprise of the lines category, that of conductors.[96] Undertaking J6.1 shows that conductors only represent 15% the interruptions caused by lines equipment failures.[97] It means that a share of the total system interposition duration is only 10%, not 69%.[98]

Whereas the other asset categories almost include all assets types in that group, with 'lines', it is only one small part of the category. It should really be reclassified as conductors. What is surprising about this is that Hydro One has the data to include many other 'lines' assets but chose not to include it. The Fosters Associates report, where Hydro One drew the data from the model, includes the necessary information for other 'lines' assets such as steel tower and wood poles. [99] Considering Hydro One is proposing significant sustaining spending on other 'lines' assets, the Board and Hydro One have no idea what actual effect the proposed capital work on 'lines' will have on reliability risk.

Hydro One's testimony when asked about this was that "[t]he reason there really is majority of the reliability problems that we have come from those three asset classes."[100] This is incorrect. The actual asset types (as opposed to asset "classes") make up less than half of the reliability issues, accounting for only 30% of the interruption durations due to equipment failure.[101]

(c) ***Aggregate Calculation Incorrect***. Hydro One's aggregate calculation of the total change in risk is also misleading since the weighting gives 16% to the 'Other' category (non-lines, transformers and breakers). The category is not actually part of the model as changes in spending have no impact on the risk. The calculation simply considers that there would be no change in reliability risk in those areas. Considering Hydro One is proposing to make significant expenditures in insulators, protection systems, among others, one would expect

[96] Tr.6, p.78-79
[97] J6.1
[98] 10.35% = 15% (conductor portion of lines) x 69% (total lines duration)
[99] Tr.6, p.85; I-1-20, Attachment 1 (Board Staff IR #20)
[100] Tr6, p.85
[101] 15% for conductors, 9% for transformers, and 6% for breakers.

the actual relative risk to decrease. This has the effect of underestimating the reduction in risk after the proposed expenditures.

(d) ***Model Is Age-Centric and Calculates Maximum Theoretical Risk.*** The underlying data that is compared in the model is a probabilistic calculation of the risk of failure of assets based on Hydro One's rate of failure at a given asset age. It is an age-centric calculation. The Board has previously commented that it is important to move away from simply asset age, and consider other factors such as condition.[102] Condition provides a much better indication than age on whether an asset needs replacing. While SEC recognizes they are correlated (i.e. old assets are more likely to be in worse condition), the model would not be able to take into account actual condition of assets and their probability of failure at any given investment level. Hydro One has said that when it actually chooses which asset to replace, it looks at condition of its assets.[103] The model only accounts for the change in assets by age and so it is likely underestimating the change in reliability risk based on the actual assets Hydro One will replace.

Further, the underlying hazard curves are derived from data that considers real-life asset failure to have occurred whenever Hydro One retired an asset. In some cases that may include actual failure, but more often, assets are removed before they fail, and in some cases significantly before if they are removed as part of an integrated replacement program.[104] The effect of this is that the model overestimates the risk of an actual failure. As Mr. Ng testified, the model calculates the "maximum theoretical risk. [emphasis added]"[105]

3.4.5 Shown below on the right is a more accurate version of Hydro One's Reliability Risk table when corrected for the presentation and calculation issues. What it shows is that, based on the models calculations, Hydro One's proposed investment plan will lead to a -3.8% change in relative risk at the end of 2018, with respect to assets that represent 25.4% of system interruptions due to equipment failure. This is a more accurate statement of what the model shows, than Hydro One's view that its proposed investment plan to a -2% reduction for its entire system (all of its assets).

[102] Decision and Order (Toronto Hydro - EB-2014-0116) , December 29 2015, p.24
[103] Tr.2, p.6
[104] Tr.5, p.146. An example of integrated replacement program is the proposed integrated station projects in which many parts of a station are replaced at the same time. This may include assets that may be replaced sooner than they otherwise would have,
[105] Tr.5, 146

Change in Reliability Risk of Proposed Investment Plan					
Hydro One			SEC Corrected		
	Relative Change in Reliability Risk	% of Total System Interruptions Duration Due to Equipment Failure		Relative Change in Reliability Risk	% of Total System Interruptions Duration Due to Equipment Failure
Lines	-2%	69%	Breakers	-2%	10.4%
Transformers	-9%	9%	Transformers	-9%	9%
Breakers	1%	6%	Breakers	1%	6%
Other		16%	Other	---	---
Total	-2%	***100%***	***Total***	***-3.8%***	***25.4%***

3.4.6 Surprisingly, a model that is so prominent in the evidence: the capital planning and the customer engagement process, was hastily put together not long before the plan was fully developed. The model was only first conceived of in the beginning of February 2016[106] and finalized two weeks later.[107]

3.4.7 Hydro One has pointed to the United Kingdom's Office of Gas and Electricity Markets ("Ofgem") as an example where similar analytical models have been developed and used.[108] But the model is not based or influenced by anything Ofgem has developed; Mr. Penstone testified that they only became aware of some sort of similar approach when they were developing the model.[109] Mr. Ng could only say that the similarities are that both are "based on outcome measures of investment plan for future system reliability performance".[110] That single observation is not even accurate, as the Reliability Risk model is an outcome measure based on reliability *risk,* not actual reliability.

3.4.8 While this reliability risk model approach is new, the general concept of measuring risk is not. Mr. Grunfeld commented that it is done by other transmitters in other jurisdictions.[111] Hydro One simply either did not know or chose not to engage or consult with any experts in the field who had experience in developing models in this sophisticated area.[112]

3.4.9 The model is also entirely untested. Hydro One did not attempt to validate or test the model by, for example, utilizing previous data to test out if past capital expenditures predicted the amount of

[106] J8.1, Attachment 1, p.1: February 4, 2016: Initial discussions on Reliability Risk Model concept/structure to link hazard curves, asset demographics and asset contributions to reliability"
[107] J8.1, Attachment 1, p.2: February 17, 2016: "Finalized Reliability Risk Model"
[108] I-1-14(b)(c) (Staff IR #14)
[109] Tr.2, p.137-138
[110] Tr.2, p.138
[111] Tr.3, p.50
[112] *Ibid*

actual asset failures.[113] In its Argument-in-Chief, Hydro One says the better approach to testing the model is to do it on a go-forward basis only, and "consider outcome measures calculated now and then testing these results against actual future baseline levels going forward".[114] SEC agrees that this an appropriate approach at this point. Until that happens the Board should give little to no weight to the model. It must wait until it can be tested based on the approved capital plan in this proceeding, and then if it is accurate, in the next proceeding, consider it an appropriate outcome measure for the purposes of capital planning.

3.4.10 While SEC is critical of the model, it supports Hydro One developing appropriate tools such as this to help in its planning process. The Reliability Risk model conceptually makes some sense, but it is simply untested at this time, does not include enough data, and has been improperly presented to the Board in the evidence, and to customers in the engagement process. A model that represents less than 30% of the interruptions due to equipment failures does not tell very much about the outcomes ostensibly driving such a significant level of spending.

3.5 Capital Program

3.5.1 In addition to the overarching concerns regarding Hydro One's capital budget and the underlying planning process, SEC has specific concerns with respect to a number of individual major asset categories that are central elements to the proposed investment plan. Hydro One's justification for the level and size of the replacements for each asset class are primarily based on their condition and performance.[115] They are the leading indicators of broader system reliability.

3.5.2 Yet, in many cases, the evidence with respect to condition and performance paint a very different picture than the change that the investment plan would indicate. In many cases, they show no need to increase the pace of replacements, and in some, indicate that a decrease in spending is appropriate.

3.5.3 ***Asset Condition Information Flawed.*** SEC has general concerns regarding the asset condition assessment information that Hydro One has provided in its evidence. Since it is such a significant driver of sustaining spending, one would have expected Hydro One to have a rigorous independent review undertaken regarding the condition of its assets generally, or even just the

[113] Tr.8, p.20-21
[114] Argument-in-Chief, p.31
[115] See B1-2-6

process it undertakes itself. Hydro One has not had an independent review of its asset condition assessment process since 2008.[116] In SEC's experience, this is highly unusual. Most distribution companies regularly undertake independent asset condition assessments, or reviews of their methodology.

3.5.4 Regardless of the outcome of the proceeding, the Board should order Hydro One to undertake a thorough independent review of its asset condition assessment to both inform its planning process, and to be filed with the Board, for its next application which is expected to be a 5 year plan.

3.5.5 The need for a review is even more important for Hydro One. Both the Auditor General of Ontario ("the Auditor General") and Hydro One's internal audit staff have been very critical about its asset data being inaccurate and incomplete. More troubling was management's response to the Auditor General's criticism about data quality in the application which was to point out that it generally did not rely on the asset analytics information. Yet the Auditor General found "Hydro One still uses the system's unreliable information to report to the OEB in its rate application on asset condition to justify its request for rate increases".[117] It would appear Hydro One does not actually use the information it provides to the Board to justify its rate increase.

3.5.6 Its response to the Auditor General's recommendations to include accurate assessment of asset condition in applications to the Board in this proceeding was to point to the data remediation program it began. The problem is that while the data remediation program was supposed to be completed in Q4 2015[118], the work appeared to have been delayed and was set to be completed in Q4 2016.[119] Even if only a small element remained to be done in the fall of 2016, the work in determining candidate projects was compiled in the fall of 2015 and early 2016. It is very likely incomplete and/or incorrect data underlying a number of the proposed capital work in this application.

3.5.7 While condition is the best indicator of which assets need to be replaced, Hydro One has a history of replacing other assets which are not high risk. The Auditor General's report revealed that in

[116] J7.1
[117] 2015 Annual Report of the Office of the Auditor General, Hydro One – Management of Electricity Transmission and Distribution Assets, p.262 (K6.1, p.144). ["*Auditor General's Report*"]
[118] Internal Audit Report – Investment Planning, (K6.1, p.120)
[119] I-3-1, Attachment 2 (AMPCO IR #1) (K6.1, p.164)

2013 and 2014, of the 37 transformers Hydro One replaced, only 4 (of the 18 transformers) that were in very poor (i.e. very high risk) condition.[120] It ended up replacing 14 that were in very good and 13 in good condition.[121] In the 2015-2016 application (EB-2014-0140), Hydro One provided evidence that was the basis of its approval that it wanted to replace 43 transformers since the number in very high risk condition had now increased to 34. Yet, it did not tell the Board that 13 of those transformers were identified in the last application as being in very high risk, and that it got funding to replace them, but ended up choosing not to.[122] A similar situation was found by the Auditor General to have occurred with circuit breakers.[123]

3.5.8 Hydro One's response has been that condition is one element but other information is used to determine if a specific asset will need replacing.[124] SEC agrees that this is an appropriate approach. The problem occurs when its forecasting budget for replacements in the aggregate are based primarily on condition and performance.

3.5.9 Since the Auditor General noted that the results of the more-in-depth process are not used in rate applications to the Board, the basis for the aggregate replacement levels for assets that is used to justify the size and number of specific projects and programs that are sought, do not necessarily represent the basis for what will actually be done.[125] This difference is important and troubling. Hydro One is asking for rates based on one set of assumptions, but will actually spend that money based on another. If at the end of the day, Hydro One is replacing so few assets that it identifies are in very high risk condition, it raises the question whether the condition data is inaccurate or it is of little value.

3.5.10 ***Circuit Breakers.*** Hydro One is proposing to increase its spending on circuit breakers by 168% from $51.8M in 2015-16 to $138.6M during the test period.[126] This is a dramatic increase in the replacement rate of the asset.[127] This is even after there has been an improvement in circuit breaker frequency and outage duration since 2013.[128] Hydro One's previous replacement program has also led to a decrease in the condition of breaker assets with less in both, high and very high

[120] *Auditor General's Report*, p.259 (K6.1, p.141)
[121] *Ibid*
[122] *Ibid*
[123] *Ibid*
[124] *Auditor General's Report*, p.260 (K6.1, p.142); B1-2-5
[125] *Auditor General's Report*, p.260 (K6.1, p.142)
[126] B1-2-6, p.17
[127] D1-2-1, p.21
[128] B1-2-6, p.14-15

risk condition.[129] In fact, Hydro One has only 1% of its entire breaker fleet in high risk condition, down from 4% in the previous application in 2014.[130]

3.5.11 These improvements in condition and performance occurred even after Hydro One did only 74 of the planned (and approved) 297 replacements.[131]

3.5.12 It is clear that nothing near the amount of circuit breakers proposed to be replaced by Hydro One is actually required. Hydro One's response during the oral hearing was to point to the performance of air blast circuit breakers ("ABCB"), specifically those that have seen degradation in performance.[132] But, as the pre-filed evidence shows, the issue begun to occur in 2013 and, "[i]n 2014 and 2015 the number of outages has been declining modestly from 2013 as ABCB's have been replaced throughout the system". [133] The current replacement rate does not need to increase from 0.7% of the fleet annually in 2015, to 2.9% by 2018.[134]

3.5.13 Hydro One is not even planning to replace many breakers that are in poor condition. Of the proposed 198 circuit breakers that Hydro One plans to replace in the test period, only 9 are high risk and 3 are very high risk.[135]

3.5.14 There is no need for a significant increase in spending relative to what Hydro One spent in the last two years. SEC submits this is an appropriate approach and proposes reduction in the expenditures in this area by $9.5M in 2017 and $55.7M in 2018.[136]

3.5.15 ***Protection Systems.*** Hydro One is proposing to replace 977 protection systems in the test period, up from 633 in the previous two years, an increase of 54%.[137] Its plan to increase the asset replacement rate from 2.2% in 2015 to 4.4% in 2018[138] is unreasonable and not supported by the evidence. The performance of protection systems in Hydro One's systems is improving. The evidence is that the forced outage frequency due to protection systems is declining for lines

[129] B1-2-6, p.16; EB-2014-0140, III/iiiD1-2-1, p.23 (K6.1, p.35)
[130] *Ibid*
[131] K6.1, p.22
[132] Tr.6, p104
[133] B1-2-6, p.-14-15
[134] B1-2-6, p.17
[135] J7.2
[136] The reduction was calculated by subtracting the forecast spending in this area for each year by the average 2015 and 2016 spending in this area ($36.). See I-6-20, Attachment 1 (K.6.1, p.22, Ln 22).
[137] B1-2-6, p.29l K6.1, p.22
[138] B1-2-6, p.29

equipment and is stable for stations.[139] This is not a new improvement, but a trend over the past decade.[140] The condition of protection systems has also not changed since what was filed in the last application.[141] If anything, it is achieving a modest improvement (1% reduction in high risk assets) in protection system asset condition.[142]

3.5.16 If anything, Hydro One should reduce the level of spending on protection systems. At the hearing, Hydro One tried to deflect the clear evidence, by claiming that the increase was still needed due to the obsolesce of some of the technology.[143] This is not the correct lens through which to look to determine if assets should be replaced or not. In a situation where Hydro One is planning on spending such a significant portion of their capital expenditures on sustaining spending, it must prioritize assets that require replacement due to condition and performance. While it may be preferable to have newer technology, and replace older assets with those that may be easier to operate with other newer assets, such as transformers,[144] if they do not actually require replacement, they should not be replaced at this time.

3.5.17 By maintaining the current level of protection system replacements, there would be forecast spending reductions of $16.55 in 2017 and $26.45 in 2018.[145]

3.5.18 ***Conductors.*** Hydro One proposes to increase its replacement of conductors by 65% from 384km in 2015-2016 to 632km in the test period.[146] The asset condition of the conductors has decreased[147], but performance has increased with frequency of outages improving and the duration of outages remaining stable.[148]

3.5.19 Most of that increase was built into the test year budget only after the November 15, 2016 draft business plan was shelved.[149] Between November 15th and the filing of the application, Hydro

[139] B1-2-6, p.25
[140] B1-2-6, p.25
[141] Tr.6, p.105; B1-2-6, p.28; EB-2014-0140, III/iiiD1-2-1, p.34 (K6.1, p.46)
[142] *Ibid*
[143] Tr.6, p.106
[144] Tr.6, p.107
[145] The reduction was calculated by subtracting the forecast spending in this area for each year by the average 2015 and 2016 spending in this area ($39.55). See I-6-20, Attachment 1 (K.6.1, p.22, Ln 33).
[146] B1-2-6, p.36; EB-2014-0140, III/iii D1-2-1, p.36 (K6.1, p.22)
[147] Tr.6, p.109
[148] B1-2-6, p.33-34
[149] J9.2. Attachment 1, p.1

One had added $281M in 2017 and 2018 to the lines category.[150] $128M of that increase is to be spent on lines refurbishment projects which are primarily about replacing conductors.[151] With a total forecast budget of $210.2M, that represents an approximately 2.5 times increase.[152] Hydro One tried to explain the increase in such a short period of time to the new information it received with respect to the condition of its conductors.[153] While the condition has deteriorated, performance has increased. Moreover, SEC is skeptical that right after the deferral of the business planning process, new information came to light that required such a significant increase in spending. No evidence has been provided on why this increased pace is required.

3.5.20 SEC agrees that it is prudent to increase the replacement rate for conductors due to the decrease in asset condition, but it is unclear why such a significant increase is required over the test period, especially when the actual performance of the assets is getting better. SEC submits an increase in replacement is warranted, but not nearly at the annual replacement rate which is proposed, to increase from 0.6% of conductors in 2016 to 1.6% in 2018.[154]

3.5.21 SEC submits a more reasonable level of spending is reducing in half the increase of $128 for line replacements that was incremental to the November 2015 business plan. This would still result in a significant increase from historical spending in this area.

3.5.22 ***Wood Poles.*** Hydro One is planning to maintain its pace of replacing 850 poles a year in the test period.[155] This is even though the condition of the wood poles has significantly improved since the last application, with a reduction by two-thirds in the number that are at high risk (9% to 3%).[156] The performance of wood poles is also increasing with both the forced outage frequency and duration declining continually over the past decade.[157]

3.5.23 The evidence demonstrates that Hydro One should be reducing its replacement rate of transmission wood poles. Its past rate of replacement of 2.0% of poles annually is achieving significant improvements for an asset that is already a very small portion of the total duration of

[150] Ibid; Tr.11, p.87
[151] J9.2. Attachment 1, p.1
[152] Tr.11, p.88-89;
[153] Tr.11, p.90
[154] B1-2-6, p.36
[155] B1-2-6, p.43
[156] B1-2-6, p.43; EB-2014-0140, III/iii D1-2-1, p.50 (K6.1, p.66)
[157] B1-2-6, p.41;Tr.6, p.112

interruptions caused by equipment failures, as compared to other lines assets.[158] The Board should reduce the level of capital expenditures for wood pole replacements. SEC submits a 25% reduction in the pole replacement program is appropriate.

3.5.24 ***Transformers.*** Hydro One is proposing to replace 49 transformers during the test period, an increase from 40 that were replaced in 2015 and 2016.[159] The Board should approve no more than the previous rate of replacement of transformers of approximately 20 a year. Hydro One has not justified an increase.

3.5.25 Hydro One proposed increase in replacements is occurring even though the asset condition is getting better with a 50% reduction in very high risk transformers (4% to 2%).[160] The performance of the transformer asset is also good, with both frequency and duration of forced outages stable.[161]

3.5.26 Hydro One's plan for the test years comes after they only replaced 64 of the planned (and funded) 78 transformers in the last three years. [162] There is no need to increase capital expenditures by replacing more transformers than what has been done in the past. The asset condition is improving based on the current replacement trend, and the performance is and has been very stable for a while.

3.5.27 Hydro One testified that, at the end of the day, they only replace transformers that their detail assessments say they need to:

> MR. NG: I think we need to go back to the fundamental basis on why the transformer gets selected for replacement.
>
> As I have repeated quite a few times, the only reason that we would pick the transformers for replacement is because it has gone through detailed assessment, and it has shown signs that it has deteriorated to a point whereby we cannot afford to have it in the system. [163]

3.5.28 SEC accepts that at the end of the day, they will replace only those that go through such an assessment, but based on the evidence, it is likely that fewer transformers are being replaced than

[158] See J6.1. Wood structure failure is the 6th of 9 sub-categories of lines equipotent failure contribution to interruption durations.
[159] B1-2-6,p.9
[160] B1-2-6, p.7; EB-2014-0140, III/iii D1-2-1, p.14 (K6.1, p.25)
[161] B1-2-6, p.5
[162] B1-2-6, p.9; EB-2014-0140, III/iii D1-2-1, p.15 (K6.1, p.22)
[163] Tr.6, p.102-103

are being proposed in this application. This is because the aggregate condition assessment and performance would lead to the need to replace fewer transformers than in the past. It is likely the same reason why Hydro One replaced much fewer transformers than it had forecasted to replace during the last three year period.

3.5.29 SEC submits the Board should only approve funding to maintain the current replacement level over the last two years, of 20 transformers a year. This would result in a reduction in the proposed spending of $38.5M in 2017 and $11M in 2018.[164]

3.5.30 ***Steel Structures.*** Hydro One is proposing to increase its steel tower replacement/refurbishment program from $13.4M in 2015 and 2016, to $96.9M over the test period. [165] The increase is due to a dramatic increase in the steel structure coating program. Hydro One had previously done steel structure coating, aimed at towers within the same life cycle, and had also focused it on areas of high corrosion.[166] None of that is new to Hydro and was contained in its last application. What has changed since the last application is the discovery of a new coating system from Galvatech (the Galvatech 2000), which allows for a much quicker application and thus is more economical.[167] Yet, instead of simply doing more towers at the historic pace, Hydro One is planning to dramatically increase spending. This is unreasonable. The purpose of the more productive technology is to do more at a similar price, not also increase the total budget.

3.5.31 SEC submits a more appropriate pace is to double what was spent in 2016. Due to the increase in efficiency of the new coating system this would allow for a significant expansion in the number of towers that will be renewed, but at a reasonable overall cost to ratepayers.

3.5.32 ***Insulators.*** Hydro One has proposed to embark on an accelerated plan to replace many of its insulators, increasing its replacement level from the historic 150-400 range (2012-2015) to a proposed annual average level of 3955 during the test year.

3.5.33 Hydro One's evidence it that driver of this dramatic acceleration in replacements is due to the

[164] The average cost per transformer replaced is approximately $5.5M. (See I-6-20, Attachment 1, K6.1, p.22, lines 11/9). This number is similar to the $5M quoted in I-1-64, p.2 (Staff IR #64). Reduction calculated by reducing forecast spending set out I-6-20, Attach 1 (Line 11) by cost of 20 transformers at $5.5M ($110M).
[165] B1-3-2, p.35; I-6-20, Attachment 1 (SEC IR #60)
[166] EB-2014-0140, D1-2,1, p.45-46,53-59 (K6.2, p.9-18)
[167] Tr.6, p.118-120

March 2015 failure of a V75R centre phase insulator which caused a conductor to fall in a commercial parking lot in Etobicoke.[168] The failure of these specific insulators, those manufactured by Canadian Porcelain (CP) and Canadian Ohio Brass ("COB"), was due to defects which leads the insulators to crack. The defect though was not just discovered after the March 2015 accident. It has been known since the 1980s, not just to Hydro One but also the entire industry.[169]

3.5.34 Hydro One did not aggressively replace these insulators until now. It chose not to do so until the March 2015 incident, and a follow up investigation and report which culminated in a report conducted by Electrical Power Research Institute ("EPRI").[170] SEC is not proposing a reduction to this program, but is concerned that under the guise of safety, Hydro One might replace some insulators much faster pace than may be required.

3.5.35 SEC agrees with Hydro One that it must undertake a replacement program for insulators due to their defects. The question though is the pace of the accelerated replacement program. The EPRI Report does not provide enough information regarding the required pace of replacement that balances condition versus safety. The evidence shows that the number of COB/CP insulator failures has varied year to year since 2011, but the trend is not increasing.[171] One would assume that if the problem is as significant as the condition report conducted by EPRI has shown, then there would be year over year increases in failures. There is simply not enough evidence on the record to explain why the pace, as proposed, is the correct one.

3.6 Productivity

3.6.1 SEC is concerned that Hydro One has not built in sufficient productivity into its capital budget. While Hydro One has outlined a number of productivity measures that it is undertaking in the test period, and has built that into the test period capital budget, it only forecast to save a total of $6.01M in savings in 2017 and $9.14M in 2018. [172] Moreover, all of these productivity savings are with respect to new processes that Hydro One is undertaking in the areas of supply chain management.[173]

[168] I-1-55, p.3-4 (Staff IR#55); Tr.1, p.63
[169] Tr.4, p.164
[170] I-1-55, p.4 (Staff IR#55); I-1-106, p.3 (Staff IR#105); Tr.5, p.163
[171] J5.3
[172] I-13-9 (CCC IR#9)
[173] *Ibid*

3.6.2 Hydro One has not built into its budget any other productivity savings as a result of delivering its increasing capital work more efficiently. Even though this is not a Custom IR application, it still must conform to the RRFE which includes the requirement of continuous improvement.[174] Sustaining capital programs are a perfect example of the type where ratepayers should expect there to be productivity over time since it involves doing similar types of work, year over year. Yet the unit cost to do the work has not changed since 2016.[175]

3.6.3 In addition, SEC expects a utility to build in a "stretch" amount to their budget that represents productivity that it will expect to achieve over the next two years that are incremental to any initiatives it knows it will undertake today.

3.6.4 SEC submits an additional 0.3% a year which represents the mid-point Board stretch factor is appropriate.[176] This would have the effect of reducing the capital expenditure budget by 0.3% in 2017 and 0.6% in 2018 since it is a cumulative calculation.[177]

3.7 In-Service Additions Variance

3.7.1 In Hydro One's last rate application, the Board approved, by way of pre-filed settlement proposal, in-service additions for 2015 and 2016 of $1,494.6M.[178] Hydro One's actual in-service for 2015 and 2016 were 7.77% higher. It is seeking approval to add to rate base a variance of $116.2M.[179] The variance with respect to sustaining spending is even higher, with actuals $121.1M (11.5%) higher than approved.[180] For many of the same reasons the Board should not approve the proposal capital spending for the test period as proposed, this additional spending from previous years is imprudent and should be disallowed.

3.7.2 The Board approved a settlement proposal which made no reductions to Hydro One's proposed capital spending for 2015 and 2016. Yet, for Hydro One, they determined that the very large

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[174] *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based* Approach (October 18, 2012), p.2
[175] I-6-20, Attachment (K6.2, p.22). To review the unit cost, take the capital cost and divided by the unit numbers.
[176] *Report of the Board: Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), Issued on November 21, 2013 and as corrected on December 4, 2013, p.20
[177] The reduction should be applied to the total capital expenditures in each year, after all other reductions are made. Based on SEC's final proposed capital expenditures this would lead to a reduction of $2.8M in 2017 and $5.6M in 2018.
[178] I-3-47 (AMPCO IR #47); K1.3, p.38
[179] *Ibid*
[180] *Ibid*

capital budget envelope of almost $1.5B in-service additions, to which they had agreed in writing to in the settlement proposal, was not sufficient. SEC submits the Board should not reward Hydro One for spending above the Board-approved level. There was no dramatic event that required additional spending, and any new emerging needs should have been offset by reductions in other areas. Utilities must learn to live within the spending envelope they have been given, especially when it reflects the exact amount they sought from the Board.

3.7.3 If Hydro One wants to spend extra money, then it has the right to do so, but it must bear the costs, not just the fraction of the costs that cannot be recovered during the previous test period. The Board should send a message to Hydro One that it cannot simply spend whatever it wants on its normal sustaining program in excess of what is approved, and then forego recovery of the amounts above what were approved for the two years, and then have them added to rate base at the time of the next application.

3.7.4 During the hearing, Hydro One claimed that the difference was appropriate as it was "accurate accomplishment" since it was within their internal tolerance of plus or minus 10%. [181] SEC submits the evidence demonstrates otherwise. Its own team scorecard for 2017 considers the budget for the 'Tx In-Service Additions Delivery Accuracy' target to be plus or minus only 5%.[182] Its previous version of its scorecard, also have the in-service capital for transmission metric target to be at 95% of the plan so 5% less than forecast. Both of these scorecards are also only a 1 year basis, not over two year test period which the 7.77% variance was calculated over.

3.7.5 SEC submits the variance is significant and imprudent, and the amount should be disallowed. Hydro One agreed to a significant capital envelope in that last proceeding. It received every dollar that it asked for when it came to ratepayers to discuss a settlement. It should have kept its spending within that approved budget.

3.8 CapEx to In-Service Additions

3.8.1 Hydro One has presented its capital plan and the supporting evidence on a capital expenditure basis, but rates are set on an in-service addition basis. Unlike distribution capital projects, transmission projects very often do span multiple years so the determination of capital to in-service additions is not a 1:1 relationship. Hydro One confirmed that for the purposes of

[181] Tr.5, p.24
[182] J1.02, Attachment 1, p.1

translating capital expenditures into in-service additions, it takes two approaches depending on the type of capital expenditure. If they are for specific projects, Hydro One is able to accurately forecast the actual in-service addition.[183] For capital programs, Hydro One uses historical capital spending levels and timing of in-service additions for each program to derive a ratio, and then it applies it to the forecast capital expenditures of that program.[184]

3.8.2 The record does not contain enough detailed capital expenditure and in-service addition information broken down on a relatively comparable basis to determine individual program ratios.[185] SEC recommends that if the Board makes reduction in the capital expenditure in the test period, during the rate order phase of the proceeding, Hydro One should be required to provide information with supporting documentation, to describe how it will adjust the capital expenditure into in-service additions to set its revenue requirement to be included in the UTR calculation.

3.9 Asymmetrical Capital Variance Account

3.9.1 In the EB-2014-0140 application, which was based on a settlement agreement reached with intervenors, Hydro One agreed to create a variance account to capture the difference between the revenue requirement built into rates for 2015 and 2016 as it related to in-service additions (capital), and actuals.[186] It is not, as Mr. Vels characterized it, "a penalty to the company".[187] It is simply attempting to ensure that ratepayers only pay for work that is actually done.

3.9.2 This asymmetrical account was agreed to deal with a specific problem that had previously plagued Hydro One. It had an inability to actually complete the capital work in the previous two years before the filing (2012 and 2013) of $473M in in-service additions.[188] Hydro One had a plan at the time to remedy the situation for the 2015 and 2016 rate years,[189] but to ensure that

[183] Tr.10, p.34-35; I-6-2, Attachment 3 (SEC IR# 2), p.23 (K10.2, p.3)
[184] Tr.10, p.34-35; I-6-2, Attachment 3 (SEC IR# 2), p.21 (K10.2, p.2)
[185] Hydro has proved detailed capital expenditure table at B1-3-1, Attachment 1. The detailed in-service additions table is located at I-6-26, Attachment 1 (SEC IR 26). The problem is Hydro One has moved to its integrated station investment program, it is not possible to make anything but the highest level assessment of the capital expenditure to in-service addition rate.
[186] SEC notes Hydro One has characterized the account to record the variances in in-service additions between 2014 and 2016 (See for example Tr.5, p.123). While it may simply be a matter of semantics, the account only tracks variances in 2014, for the purposes of adjusting the opening balance to rate base in 2015. That is, the account was never designed to provide back to ratepayers any underspending in 2014 compared to what was approved in rates for 2014. Just the effect of any underspending in 2014 on in-service additions on 2015 and 2016. This is demonstrated by the illustrative example contained in the settlement agreement, p.14 (EB-2014-0140, II, p.15)
[187] Tr.1, p.192
[188] K1.2, p.40
[189] K1.2, p.42-43

ratepayers only paid for work they actually did, the asymmetrical variance account was created. SEC has supported such an account in previous proceedings where the forecast period is lengthy (5 years), and where there is a question about the ability of the utility to execute on their plan. [190]

3.9.3 Hydro One is proposing to continue to the account into the test year. SEC does not oppose doing so, but it is important for the Board to recognize that the problems of execution that gave rise to the account in the first place, no longer exist. In fact, it appears the complete opposite situation is now the problem. As discussed above, Hydro One has for the past two years significantly overspent. It now does not appear that Hydro One has the same problem executing on its plan in the aggregate. It is putting into service, more capital as measured in dollars, than was approved.

3.9.4 It should be noted, the account does not protect ratepayers in ensuring the correct work gets done or that the capital work is done at the forecast cost. All that is potentially cleared to ratepayers is if that over the two year period, the total in-service additions is less than what is approved. If Hydro One does less work but the overall cost is the same as was approved, then there would no amount recorded in the account for disposition to ratepayers.

3.9.5 Hydro One has set up an execution plan that does the opposite. Instead of recording any savings from forecast costs of a program in the variance account, it plans to simply take that money and do more work. [191] This has the effect of denying ratepayers the benefit from Hydro One's ability to do the forecast capital work more cost effectively.

3.9.6 Re-investing these savings in more capital on the surface may seem to be of the benefit to ratepayers, but it will simply create greater costs in the longer term. Ratepayers will have to pay the full cost of the incremental asset through depreciation expense over the life of the asset, and a return on equity on the undepreciated cost of the asset. The Board should ensure that if Hydro One is able to do the proposed capital work more cost efficiently, the savings will return to ratepayers through the variance account and not be spent on additional capital work.

3.10 Summary

3.10.1 SEC submits Hydro One's proposed capital spending in the test years is unreasonable,

[190] See for example EB-2014-0116 (Toronto Hydro Custom IR), EB-2012-0002 (Horizon Utilities Custom IR), EB-2014-0101 (Oshawa PUC Custom IR)
[191] Tr.9, p.187-88

specifically in the area of sustaining spending. It should reduce the test period in-service additions by the capital expenditures equivalent of of $156.13M in 2017 and $199.92M in 2018.It should also not allow any of the overspending from 2015-2016 to be added to rate base.

SEC Proposed Capital Expenditure Reductions ($M)	2017	2018	Arg Ref
Circuit Brekers	-9.5	-55.7	3.5.14
Protection Systems	-16.55	-26.45	3.5.17
Conductors	-32	-32	3.5.21
Transformer	-38.5	-11	3.5.29
Steel Tower Coating	-24.9	-36.9	3.5.31
Wood Poles	-8.83	-8.83	3.5.24
Above-Market Compensation (Mercer Study CapEx Allocation)	-22	-22	4.3.14
Above-Market Compensation (Share Purchase Program Tx CapEx Alocation)	-1.09	-1.47	4.3.15
Productivity Improvements	-2.8	-5.6	3.6.4
Total	**-156.13**	**-199.92**	

4 OM&A

4.1 Overview

4.1.1 Hydro One is seeking approval of $413.1M in 2017 and $411.2M in 2018 for its forecast OM&A costs. This amount reflects a reduction from the forecast 2016 OM&A of $420.7M (and $436.8 Board approved).[192] While the decrease in OM&A at first glance appears positive, it is misleading. The drivers of OM&A levels are not actually being reduced as they are being caused by changes in the allocation over the test period between distribution and transition, and the amount that is being capitalized has increased.

4.1.2 SEC submits the Board should make reductions to the proposed OM&A spending due to the significant above-market compensation, lack of productivity, increased costs as a result of the IPO, and the need to include the benefits of significant capital spending.

4.2 Allocations and Adjustments

4.2.1 The reduction in OM&A spending between 2016 and the test period is being masked by a number of adjustments made by Hydro One, and changes to how costs are being allocated within the company. This has the effect of making it appear as if Hydro One has gotten control of its OM&A costs when it has not.

4.2.2 ***Capitalized Overheads.*** During the test period, the amount of capitalization of overheads is increasing significantly. This is unsurprising considering the significant increase in capital expenditures that are forecasted which has the effect of attracting increased overhead costs. Hydro One accounts for capitalized overheads as a credit to OM&A. As shown in the table below, capitalized overheads are increasing by over $11M between 2016 and 2017, an increase in 9.1%.

	2012	2013	2014	2015	2016	2017	2018
Captalized Overheads Effect on OM&A ($M)	-106.9	-109.3	-124.3	-116.9	-122	-133.2	-134.7

Source: I-4-6

4.2.3 From the perspective of ratepayers, while this may reduce the OM&A costs during the test period, it will cost them more over time. As OM&A costs are now being capitalized, it has the

[192] A-3-1, p.18; C1-2-1; I-13-25, p.3 (CCC IR# 25); J12.1

effect of increasing the overall life of the underlying capital assets that underpin their capitalization, as they will now include a cost of capital.

4.2.4 The costs drivers are still increasing and changes in capital expenditures will, in the future, re-allocate them back to OM&A. The people, places, and things which make up those overhead capitalized costs are still there, more of it is just accounted for differently in the test period.

4.2.5 ***Pension and B2M LP Adjustment.*** Hydro One has made reductions in the test period OM&A account for a pension and B2M LP adjustments.

The pension adjustment, a reduction of $11M in 2017 and $8M in 2018, is caused by an updated pension valuation report that was commissioned.[193] Since the pension valuation is based on a number of economic assumptions that are external to Hydro One, it is hard to credit Hydro One cost reduction. It is just as likely that the next pension valuation will show a swing in costs in the complete opposite direction based on market performance and discount rates.

4.2.6 The B2M LP adjustment is a reduction of $2.9M over the test period. For ratepayers, it will have no effect on the cost ratepayers pay for transmission services.[194] The adjustment removes from OM&A, an amount equivalent to the expected costs that will be paid by B2M LP to Hydro One for services to operate and maintain the Bruce to Milton transmission line. The line previously owned by Hydro One, is now owned by B2M LP, a separate licensed transmitter. Ultimately, those costs are going to be paid by transmission ratepayers as part of the B2M LP revenue requirement that is included within the UTRs. Those costs which had previously always been included in the Hydro One OM&A are simply now costs that B2M LP incurred. For ratepayers, there is no actual reduction, it is simply an issue of allocation between two entities.

4.2.7 ***Common and Corporate Costs.*** Another cause of the reduction in OM&A costs in the test year is the lower Common Corporate Function and Services ("CCFS") costs that are charged to transmission ratepayers (Tx Allocation). The total CCFS costs represent centralized service of the entire Hydro One company, that cannot be directly assigned, which are then allocated based on the previously approved cost allocation methodology developed by Black and Veatch

[193] C1-2-1, p.5
[194] *Ibid*

Corporation.[195] The table below shows the total CCFS costs compared to the transmission allocation of those costs.

CCFS Costs ($M)	2012	2013	2014	2015	2016	2017	2018	
Hydro One Total	152	164	172.8	179.4	194.2	201.8	202.7	(1)
Tx Allocation	80.5	87.7	93.1	95.7	98.9	98.3	97.6	(2)
Source: (1) C1-3-3, p.2 (2) C1-3-3, p.2; I-13-25, p.3								

4.2.8 What the data shows is that while the amount being allocated to transmission is slightly decreasing over the test period, the total Hydro One CCFS costs are increasing, and quite substantially between 2015 and 2016. Transmission ratepayers are thus simply paying a small portion of the overall costs, but the cost themselves are still increasing. The remainder of those costs will be recovered by primarily distribution customers. Much like the capitalized overheads, the underlying costs are still being incurred and will be paid by ratepayers based on an allocation methodology.

4.2.9 Hydro One's view that its forecast OM&A is a reduction from previous years, while technically correct, is misleading. The reductions in costs are being driven by allocation and adjustment issues and not an actual reduction in the underlying costs that are being incurred by Hydro One as a company.

4.3 Compensation

4.3.1 As the Board is aware, Hydro One's compensation costs have been an issue in past distribution and transmission proceedings. The evidence in this proceeding demonstrates that not only do they remain a problem but they appear to be getting worse. Hydro One does not appear to have heeded the Board's prior direction to get its compensation costs under control. Further, changes to the executive compensation system that have recently been implemented require adjustments to ensure the performance incentives are not achieved at the expense of ratepayers' interests.

4.3.2 ***Compensation Still Above Market.*** In Hydro One's last distribution proceeding (EB-2013-0416), the Board made detailed comments regarding the unreasonable compensation levels it was paying. The Board was clear that it was not fair for ratepayers to have to pay a premium over the market medium.[196] In the subsequent period since that decision, Hydro One has entered into two

[195] C1-6-1, p.1; B1-3-9, Attachment 1
[196] *Decision* (Hydro One Dx - EB-2013-0416/2014-0247),March 12 2015, p.24-25

new collective agreements with both its major unions, the Power Workers Union ("PWU") and the Society of Energy Professionals (the "Society").[197] The evidence in this proceeding shows that not only the gap between actual and market median pay has increased, the studies are actually understating the real difference in compensation levels.

4.3.3 Throughout the pre-filed evidence and interrogatory responses, Hydro One relied on the fact that the compensation benchmarking studies undertaken by Mercer over the last few distribution applications, demonstrated that it was moving towards the market median.[198] But during the hearing, Hydro One provided a presentation regarding the preliminary findings of its most recent Mercer compensation study for its upcoming distribution application. The Mercer presentation shows Hydro One is actually getting worse, not better, in each of the three employee categories (Management, Society and PWU).

4.3.4 In its EB-2013-0416 decision, the Board stated that it did "not find that it is fair that ratepayers pay a 10% premium over the market median."[199] Three years later, the gap has now increased to 14%.[200]

Mercer Compensation Benchmarking Results v. Market Median (Total Compensation as Multiple of P50)

Employee Group	2016	2013	2011	2008
Management	1.02	0.99	0.83	0.99
Society	1.11	1.09	1.05	1.05
PWU	1.16	1.12	1.18	1.21
Overall	***1.14***	***1.10***	***1.13***	***1.17***

Source: K9.8, p.12

4.3.5 In Ontario Power Generation's ("OPG") last payment amounts application (EB-2013-0321), the Board commented on its role as a market proxy in determining what costs get passed on to ratepayers.

> One of the Board's important functions is to act as a market proxy. Regulation exists to prevent the abuse of monopoly power. Absent regulation, monopoly service providers would be able to pass on any cost to its captive consumers, and there would be little incentive for the provider to exercise cost control or seek efficiencies. The

[197] Hydro One entered into its most recent agreements with the PWU and Society in 2015 (C1-4-1, p.15)
[198] For example see C1-4-1, p.27-28, I-9-15 (CME IR #15)
[199] *Decision* (Hydro One Dx - EB-2013-0416/2014-0247),March 12 2015, p.24
[200] K9.8, p.12

> Board finds that it would not be reasonable to pass all of OPG's compensation costs on to ratepayers.[201]

4.3.6 This role of the Board has been confirmed by the Supreme Court of Canada.[202]

4.3.7 In the EB-2013-0416 decision, in exercising its role as the market proxy, the Board made reductions to Hydro One's requested OM&A on the basis of the Mercer study. But it did not reduce the amount by the entire 10%, noting Hydro One's progress towards the median.[203] Since then, Hydro One is moving in the opposite direction. The Board should send a strong signal that this is unacceptable and the entire amount between its pay and market pay should be borne by Hydro One shareholders, not its ratepayers.

4.3.8 Not only does the Mercer study show Hydro One moving away from the market median, it is likely understating the difference. This is because the data that is used does not include all of the elements of compensation that Hydro One pays its employees. As Hydro One confirmed in Undertaking J10.3, the Hydro One compensation data does not include lump sum amounts that were paid, just their regular base salary, incentive payments, and pension benefits amounts. Hydro One provided lump sum payments to both the PWU and Society in its most recent collective agreement entered into 2015. In 2016 alone, the year the Mercer study data comes from, PWU received a lump sum payment of 2% and the Society received a lump sum payment of 1%.[204] None of these amounts are included in the Mercer compensation study. The Society will receive another lump sum payment of 2% in 2017.[205]

4.3.9 On a going forward basis, it can reasonably be expected that the gap will continue to grow. The collective agreements not only provide similar base wage increase as in the past to both the PWU and Society[206], and there will be an additional 2% lump sum payment for the Society, but 2017 and 2018 are the first years of the share grant program for the two unions. The share grant program allows eligible PWU and Society employees (those employed as of the date of the IPO) to receive, in addition to their regular compensation, an additional 2.7% (for the PWU) and 2% (for the Society) of their 2015 salary in Hydro One shares (priced at the IPO value) for each of

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[201] *Decision with Reasons* (OPG - EB-2013-0321), November 20 2014, p.80
[202] *Ontario (Energy Board) v. Ontario Power Generation Inc*., 2015 SCC 44, para 11.
[203] *Decision* (Hydro One Dx - EB-2013-0416/2014-0247),March 12 2015, p.22,24
[204] C1-4-1, p.23-24
[205] *Ibid*
[206] I-1-128 (Staff IR #128)

the next 12 years.[207] Hydro One is seeking to collect the value of the share grant program, approximately $8.3M over the test program[208], from ratepayers.[209]

4.3.10 In addition, the above-market compensation Hydro One pays is also demonstrated by the Towers Watson reports. Hydro One retained Towers Watson in 2015 to conduct a compensation benchmarking study for its non-represented employees. One study was undertaken for executive level employees (MCP Bands 1-4) and another for all others who represent the vast majority of management employees (MCP Bands 5-10).[210] The non-executive employee management study showed that for approximately half of the employees, those whose jobs are not specific to the power industry (called support positions), are being paid above the 75th percentile.[211] Whereas the other half, whose positions are power sector specific (called core operational), are at the market median.[212]

4.3.11 As Mr. Resch from Tower Watson testified, it is not best to compare all positions to similar companies when for many you are recruiting from a much broader general industry market.[213] If one were to compare all positions to those only in like utility companies, Mr. Resch expected that those support management positions would be closer to the median market position.[214] This is because "market data is higher amongst utility companies in Canada, and then [sic] general industrial" and you do not want to compare all positions' compensation to those at utility companies so you are not "inflating market levels by comparing non-utility roles to other utility organizations."[215] SEC agrees. The Mercer study peer group is only power or other highly

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[207] Tr.10, p.55-57
[208] I-1-128 (Staff IR #128)
[209] Tr.10, p.57
[210] In 2017, non-executive management employees (MCP Bands 5-10) represent 567 of the 687 (96%) of the total management employees population. (See I-11-29 [Energy Probe IR #29))
[211] I-06-057, Attachment 3, p.4 (CME IR#57)
[212] Ibid, p.3
[213] Tr.9, 127:

> MR. RESCH:
> …
> So rather than saying that every management role needs to be compared to a utility peer group, we have taken a much more, I think, conservative approach to separate out and ensure that the core operational or the roles that you would typically recruit from or lose to other utility organizations are bucketed together and aligned to one peer group of other utility organizations, whereas the support roles where you are drawing from a much broader general industry market, we are looking at a different peer group for them.
> ….

[214] Tr.9, p.138
[215] Tr.9, p.137-138

regulated companies, not the broader market for these positions.[216]

4.3.12 This is not a criticism of the Mercer methodology, as it is consistent with past studies and allows for an apples-to-apples comparison. But it does show that the Mercer study is likely understating the true difference between Hydro One's compensation versus the true market median.

4.3.13 Consistent with its decision in Hydro One's last distribution application, SEC submits the Board should reduce Hydro One's compensation costs, which are significantly above the median, and are not just and reasonable. Ratepayers should not have to pay for compensation costs that are not reflective of the market.

4.3.14 Mercer calculated the difference in 2016 between the market median and the Hydro One data that it used in its study to be approximately $71M on a corporate-wide basis.[217] This amount will have only grown in the test years. Using Hydro One's allocation methodology consistent with its Black & Veatch study, that would represent 17.6% for transmission OM&A ($12.5M) and 31% for transmission capital ($22M).[218] Since total compensation of these three categories of employees (MCP, PWU and Society) are slightly increasing in 2017 and 2018, a reduction of at least $12.5M per year in OM&A and $22M in capital costs is appropriate for each of the test years.

4.3.15 In fact, as discussed above, the amount should be higher, to account for the real gap between Hydro One's compensation and the real market median. The reduction should include an additional amount denying recovery of the transmission component of the proposed $8.3M over 2017 and 2018 for the share grant program. Allowing recovery of this amount would simply aggravate the unreasonable compensation amounts being recovered from ratepayers.[219] This was not included in the Mercer study as the program only begins in 2017. Using similar methodology as the Mercer study reduction, this has an effect of reducing the proposed capital costs by $2.56M and OM&A by $1.4M, for 2017 and 2018.

4.3.16 SEC submits this additional reduction in compensation costs is warranted as the Mercer study understates Hydro One's compensation compared to the market median due to the use of its

[216] See Mercer peer group (K9.8, p.8) , versus Towers Watson support peer group (I-06-057, Attachment 3, Appendix II)
[217] K9.8, p.5
[218] J10.4
[219] 2017: $3.5M, 2018: $4.75M (I-1-128 (Staff IR #128)

narrow peer group methodology as the Towers Watson study showed. The problem is there is not enough information on the record to determine exactly how Mercer came up with the amount between Hydro One's actual total compensation and the market median to disaggregate the amount to ensure there is no double counting of the reductions.

4.3.17 ***Better Information Required.*** As was apparent during the hearing, the way Hydro One tracks compensation spending is problematic and does not allow for a rigorous review. Hydro One, as in past applications, did not file a standard Appendix 2-K form but its own tables and format. Hydro One has said that its current payroll system does not allow for the compensation information as asked in Appendix 2K as other utilities do.[220] What it filed in the application is information on only certain aspects of compensation paid within each year, for employees who are employed by Hydro One on the last day of the year.[221] This clearly does not provide an accurate set of figures that determines how much compensation is actually being paid and built into the revenue requirement.

4.3.18 After much prodding, and apparently considerable amount of work by its staff, it was able to produce in Undertaking J10.2, a table showing total compensation, broken down by category, for the transmission business. This was a good start, but since it cannot be measured against employee numbers (FTEs), it is hard to determine the average compensation per employee and changes in actual employee counts.

4.3.19 SEC submits the 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.

4.4 Executive Compensation

4.4.1 Hydro One has proposed recovery of significant increases in compensation payable to the most senior executives, including its CEO and CFO. Hydro One believes the additional amounts are required to attract a high caliber of management, which will ultimately be a benefit to ratepayers.[222] SEC's concerns are not primarily the value of the increases in executive compensation, but the design of the new compensation packages. The new compensation package

[220] Tr.10, p.38-44; Tr.11, p.170-178; J10.2
[221] *Ibid*
[222] Tr.8, p.149

includes a long-term incentive program (the LTIP Program) which is a share-based compensation arrangement. At the level of the CEO, 50% of the LTIP is paid in performance share units ("PSU") which are based on achieving certain earnings per share targets.[223]

4.4.2 For the CEO of Hydro One, this can represent up to $1.2M of his expected $4M a year salary. 30% of his total compensation a year could be based on only earnings per share. While earnings per share are very relevant for aligning management interests with those of its shareholders[224], it is not clear how it aligns management incentives with those ratepayers. When Hydro One's expert witness, Mr. Soaré of Hugessen Consulting**,** was asked about this, he struggled to explain how ratepayers benefit from such an incentive.[225]

4.4.3 It is important for the Board to ensure the alignment of ratepayers and management interests, not shareholder and management interests. The Alberta Utilities Commission ("AUC") has commented on the need to ensure that long-term incentive compensation programs are not too heavily weighted in favor of metrics that benefit the shareholder. It set limits on individual performance objectives to ensure that management was not incented to maximize shareholder value at the expense of customers.[226] In proceeding 2011-450, the AUC commented that 10% net income metric for variable pay for ATCO Gas management should be capped at 10% of total compensation. Anything more should be borne by the shareholder to ensure management is not in a conflict of interest between shareholders and ratepayers. As the AUC commented:

> The Commission finds that the inclusion of net income component within a VPP is reasonable when there is a balance struck between the benefits that customers may receive through reduced costs versus increased earnings for the benefit of shareholders. A net income component greater than 10 per cent for officers and senior managers might result an inherent conflict between shareholder interests and customers. The Commission finds that setting limits to individual performance objectives will ensure that management is not incented to maximize shareholder value at the expense of customers. If AG wishes to include a net income component for specific individuals higher than 10 per cent of their VPP compensation, those costs are to be borne by shareholders. [emphasis added] [227]

4.4.4 SEC submits this approach is a useful guide to ensuring that ratepayers are not paying to incent behavior that benefits the shareholder. Long-term compensation that rewards shareholder interests as opposed to ratepayers', such as earnings per share, should be capped at 10% of the

[223] Tr.8, p145
[224] Tr.8, p.151
[225] Tr.8, p.148-151
[226] Alberta Utilities Commission, 2011-2012 General Rate Application Phase I (Decision 2011-0450), December 5, 2011, para. 751
[227] *Ibid*

total annual compensation amount for those employees. Hydro One's shareholders should be responsible for any additional amounts of the PSU portion of LTIP above 10% of total employee compensation. To be clear, the issue is separate from the total level of executive compensation. SEC submits the Board should require Hydro One to either eliminate that aspect of the compensation package or replace it with incentives that aligns management with the interests of its ratepayers. The total value of the compensation package may still be the same. If Hydro One chooses not to, then it should require the allocation of PSUs measured by earnings per share above 10% of the total compensation to be paid for by its shareholder, not ratepayers.

4.5 Sustaining OM&A

4.5.1 Hydro One is proposing to increase its sustaining OM&A spending from $227.5 in 2016 to $241.2M in 2017 and $238.5M in 2018.[228] The proposed increase is unreasonable considering the forecast increase in capital expenditures in the test period.

4.5.2 The Board has previously commented that it expects corrective and unreactive maintenance should be reduced over time as capital work focused on renewal of assets (i.e. sustaining capital) increases.[229] In the Toronto Hydro's Custom IR decision, the Board wrote:

> The OEB finds that as aging assets are replaced the extent to which the system requires reactive maintenance should be reduced. Most of Toronto Hydro's capital spending is on system upgrades and renewal rather than expansion of the system, so new assets are replacing old ones that require corrective maintenance in addition to routine inspections and preventive maintenance. The OEB agrees with Toronto Hydro that the need for inspections and routine maintenance will continue with new assets, but the expensive corrective maintenance and the unplanned reactive maintenance should reduce over time if the system is well managed. [emphasis added].[230]

4.5.3 Hydro One has not included reductions in sustaining OM&A to account for the expected decrease in need for reactive and corrective maintenance due to its increasingly aggressive asset replacement program which has begun even before the test period.

[228] A-3-1, p.18
[229] *Decision and Order* (Toronto Hydro - EB-2014-0116) , December 29 2015, p.11
[230] *Ibid*

Sustaining OM&A - Reactive and Corrective Maintenance	2015	2016	2017	2018
Power Equipment - Reactive Maintenance	28.7	19.7	27.5	27
Ancilliary Systems - Reactive Maintenance	3.6	4.1	4.3	4.3
Environmental Management - Preventive and Corrective Maintenance	2.7	2.3	2.5	2.5
Protection, Control, Monitoring, and Metering Eqiuipment - Reactive Maintenance	7.6	5.5	8.9	9.1
Telecommunications - Preventative and Corrective Maintenance	5.1	3.4	3.6	3.8
Overhead Line - Demand Maintenance	4	3.2	3.4	3.6
Overhead Line - Planned Corrective Maintenance and Projects	5.4	4.6	5	4.4
Underground Cable - Corrective Maintenance	2.1	2.3	2.3	2.3

Source: C1-2-2

4.5.4 Hydro One is not proposing reductions in reactive or corrective maintenance at all.[231] Hydro One has not built in specific reductions, or accounted for in any way, the reduction in these sustaining spending to account for the higher proposed rate of asset replacements.

4.5.5 The Board's Utility Rates Handbook requires utility planning in the context of "optimized in terms of the trade-offs between capital and operating expenditures".[232] SEC submits that a trade-off includes that if capital expenditures are being made, some offsetting reductions in OM&A costs are being captured. Hydro One's proposed sustaining OM&A spending has not done so.

4.5.6 SEC submits the problem in determining what the specific reduction to corrective and reactive maintenance should be is hard to do with prevision due to the lack of evidence provided by Hydro One on the relationship between its sustaining capital and OM&A spending. SEC proposes a $5M reduction each year, which is likely understating the actual reduction that should occur. This represents roughly a 10% reduction in the test period budget in the reactive and corrective maintenance budgets.[233]

4.6 Post-IPO Costs Increases

4.6.1 Hydro One is free to structure its ownership in anyway it wants, subject to any legal and regulatory requirements. Ratepayers in turn, should not bear the burden of cost increases that are caused by such a decision. Hydro One's costs in a number of areas have increased since the IPO, and while Mr. Vels testified the increase is not directly caused by it, it clearly is a result of the

[231] The table included in this section is from the information contained in C1-2-1. Hydro One has in some cases classified spending as corrective and reactive separately, in other cases included in the preventive category. Because of that the table is not intended to show a specific number that is being spent on these two categories but to show the general trend.

decision and the new management that were brought in as the company moved to its commercial orientation.[234]

CCFS Areas of Concern								
Total ($M)	**2012**	**2013**	**2014**	**2015**	**Pre-IPO Avg**	**2016**	**2017**	**2018**
Corporate Management	5	4.9	5.5	5.4	5.20	11.1	22.3	22.1
Corporatate Communications	11.3	15	19.5	17.3	15.78	17.5	17.3	19.4
General Counsel and Secretariat	8.8	9.6	8.7	8.6	8.93	10.3	10.4	10.5
Tx Allocation ($M)	**2012**	**2013**	**2014**	**2015**	**Pre-IPO Avg**	**2016**	**2017**	**2018**
Corporate Management	2.5	2.1	2.7	2.8	2.53	4	7.2	7.1
Corporatate Communications	5.3	6.5	9.4	7.7	7.23	8.7	8.7	9.9
General Counsel and Secretariat	4.9	5.4	4.9	5	5.05	5.5	5.5	5.6
Sources: C-1-3, p.2,10; I-1-121								

4.6.2 In a number of common cost areas, Hydro One's costs have increased since the 2015 IPO disproportionately compared to their historical trend. The Board should hold corporate management, communications, and general counsel costs steady as compared to their pre-IPO average (2012-2015).[235] This results in a reduction of $6.6M and $7.8M in 2017 and 2018.

4.7 Productivity

4.7.1 Hydro One has discussed its move to be a more productive utility. Yet, the evidence demonstrates that this is not actually the case. Hydro One forecasts that its productivity and efficiency initiatives for OM&A will lead to savings of $2.9M and $3.5M, in 2017 and 2018.[236] This represents a savings of only 0.7% and 0.84% of the total OM&A spending in those years.[237] This is not a significant amount, especially for a utility that has had very poor productivity in the past.

4.7.2 Only 1 of the 9 listed productivity and efficiency initiatives are incremental to Hydro One in the test period.[238] The rest are continuations of initiatives that have previously been undertaken. Further, of those 8 existing initiatives, none are expected to have incremental savings in the test period. The only new savings that will occur are a result of the new wrench time studies[239] which

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[232] *Handbook to Utility Rate Applications*, p.13
[233] See footnote 231 for why the term approximate was used.
[234] Tr.2, p.144
[235] SEC recognizes that $6.3M in total corporate costs are not allocated to any ratepayers (See I-4-12, p.1) The amount is not included in Hydro One's Tx calculation so it is not included in SEC's reduction.
[236] I-1-116 (Staff IR #116); C1-2-6, p.5-17
[237] This is calculated by dividing the forecast savings by the proposed OM&A plus the savings (i.e. the no savings scenario).
[238] I-1-116 (Staff IR #116)
[239] Wrench time studies are detailed analysis of specific work tasks to determine and best and worst cost rations and establish standard for internal benchmarking. Best practices will be then used across the system. (See C1-2-6, p.8-9)

are forecasted to save an additional $400k in 2017 and $1M in 2018.[240]

4.7.3 SEC submits Hydro One must build in additional savings for productivity indicatives, not only that it knows will occur based on planned programs, but those that it cannot forecast today. Even in a two year cost of service, it must build in a "stretch" amount so that ratepayers benefit from savings that should occur in 2017 and 2018 that Hydro One has not forecasted. SEC submits Hydro One should at least be able to double the expected productive and efficiency savings it expects to achieve in 2017 and 2018 based on initiatives that were themselves only introduced in the last couple years.

4.8 Summary

4.8.1 Based on the adjustment proposed above, SEC submits the following total reductions should be made to Hydro One's forecast OM&A of $23.9M in 2017 and $29.41M in 2018.

SEC Proposed OM&A Reductions ($M)	**2017**	**2018**	**Arg Ref**
Compensation			
Mercer Study (To get to the 50th percentile)	-12.5	-12.5	4.3.14
Share Purchase Program (Not included in the Mercer Study)	-0.60	-0.81	4.3.15
Reduction in corrective and reactive maintenance	-5	-5	4.5.6
Additional productivity improvements	-2.9	-3.5	4.7.3
CCFS Cost Reduction	-6.6	-7.6	4.6.2
Total Proposed OM&A Reduction	**-23.9**	**-$29.41**	

[240] I-1-116 (Staff IR #116)

5 DEFERRED TAX ASSET

5.1 The Issue

5.1.1 SEC has looked in detail at the question of whether Hydro One should be allowed to collect an amount in rates for taxes that is known to be materially greater than the actual tax expense Hydro One will incur each year. This situation arises because of the interaction of a "payment" of departure tax of $2.6 billion, the adjustment of Hydro One's balance sheet to recognize a $2.6 billion deferred tax asset that resulted from a related bump in asset values to fair market value, and the issuance of $2.6 billion of new shares to the Province, ostensibly to pay the tax.

5.1.2 The interaction of these events means that, while Hydro One Transmission will have $171.7 million[241] of tax in its 2017-8 revenue requirement, it will not actually pay that tax. Hydro One believes it should be allowed to collect this amount, even though it is not paying the tax. Some other parties believe that it should not be allowed to collect more for income tax than it actually expects to pay out.

5.1.3 SEC has concluded that there are four distinct ways to look at, and characterize, the relevant transactions, and each leads to a different rate result. SEC is not proposing that one is right, and the others are wrong and and is not a recommended result. SEC can be of most assistance to the Board by setting out our analysis of the four characterizations, and the strengths and weaknesses of each. This will hopefully provide the Board with the most comprehensive view of the issue, and the menu of principled options available to the Board for its resolution.

5.1.4 The four characterizations of the issue, described in detail in the following sections, are:

(a) ***The Hydro One Argument***. At its root, the argument by Hydro One applies the standalone principle and "benefits follow costs" to conclude that ratepayers should pay the notional tax amount in rates, and Hydro One should get to keep the differential. Properly characterized, it actually amounts to the ratepayers paying the departure tax over time in their rates, and to the issuance of shares to the Province being treated as an unrelated increase in the net value of Hydro One shares.

(b) ***Following RP-2004-0188.*** This characterization treats the departure tax and the

[241] C2-4-1, Attach 1. The resulting grossed-up amount for ratemaking purposes is $233.6 million.

issuance of shares as an economic net zero, equivalent to non-payment of the tax. Once it is accepted that the tax was effectively not paid, RP-2004-0188 makes clear that the ratepayers should only pay in rates the actual tax forecast to be paid. The utility should be able to recover in rates only its prudently incurred costs, plus a fair return. The actual tax cost is the prudently incurred cost.

(c) ***Distinguish Federal vs. Provincial Tax Impact.*** Under this characterization, the Board would recognize that the change from PILs to normal income tax causes the Province to lose some of their tax revenues, but not all of them. To the extent that the transactions result in a net revenue loss to the Province, that proportion of the deferred tax asset would accrue to the shareholder. The remainder of the deferred tax asset would accrue to the ratepayers. Thus, part of the annual tax expense would be included in rates (the federal component, which the Province is losing), and the rest would not.

(d) ***Different Treatment of Liability vs. Asset.*** This characterization recognizes that part of the impact of the FMV bump is to recapture past tax timing differences (bringing the existing deferred tax liability to zero). The ratepayers got the benefit of those timing differences in previous years, and so should pay that part of the impact of the bump. The creation of the asset, however, is not the result of any past ratepayer benefit. Their benefit from that should come in the future, when tax is saved. In this scenario, the part of the annual tax expense that represents the future benefit would not be included in rates. The rest, reflecting the past tax savings ratepayers have already received, would be included.

5.1.5 The remainder of this section of our Final Argument provides details of each of these characterizations, and the strengths and weaknesses of each.

5.2 The Hydro One Argument

5.2.1 The approach Hydro One has taken to this issue is not unreasonable. Indeed, OEB Staff has supported the Hydro One position, and, frankly, until further information on this issue came out during the course of the proceeding, SEC also supported this view. It now appears clear that the full fact situation is more nuanced than it first appeared, but even with the additional facts, it is not clear to SEC that accepting the Hydro One position would be unreasonable.

5.2.2 The Hydro One position rests on three basic assumptions:

(a) Hydro One actually paid the departure tax, and no part of that cost – a real cost – will be recovered from ratepayers. This invokes "benefits follow costs".

(b) The departure tax and the deferred tax asset are the results of a transaction, the IPO, which is not part of the regulated activities of the Applicant. This invokes the "standalone principle".

(c) A utility's rates are not based on its actual costs. "Revenue requirement" is a regulatory construct, and thus the fact that Hydro One would be collecting in rates tax amounts that it does not actually have to pay is fully consistent with regulatory principles. This is the ultimate conclusion from the "standalone principle".

5.2.3 In the characterization of the situation presented by Hydro One, this is what happened:

(a) The IPO triggered a requirement to pay $2.6 billion of Ontario tax. Hydro One paid that tax, in cash, to the Province.

(b) In an entirely unconnected transaction, Hydro One received $2.6 billion of cash from the Province in return for the issuance of new shares to the Province. While the reason Hydro One needed the money was the tax payment that does not change the independent nature of the share issuance.

(c) Because the tax was paid, Hydro One has a $2.6 billion asset that it is able to use to offset tax otherwise payable to both the federal government, and the Province, on its future income. The asset belongs to the unregulated side of Hydro One, because it was the unregulated side of Hydro One that paid the departure tax that is the mirror image of the future asset.

(d) In future years, tax will still be notionally payable on the regulated activities of the utility. However, Hydro One will have, in effect, a "credit" from the deferred tax asset owned by its unregulated side, and it can draw down on that credit to pay the notional tax. The customers should include the notional taxes in rates, because the

regulated activities generate those taxes. The fact that they will not actually be payable is a function of an unregulated asset, and has nothing to do with the regulated costs that are before this Board.

5.2.4 SEC believes that this characterization, while the preferred approach of Hydro One, is actually not the strongest argument in favour of their position. To put their position at its strongest, the characterization would be as follows:

(a) The departure tax paid, $2.6 billion, is effectively a prepayment of federal and provincial income tax on future income. While it is structured as payment by Hydro One of tax on recapture of depreciation, and capital gains, in fact that is a method by which the Province gets prepayment of the amounts that it would have received as PILs for a period of years into the future. It is there to protect the Province from its future loss of revenue.

(b) Each year, Hydro One proposes to collect full tax from ratepayers in rates, but then pay only a much lower amount. The difference will be a drawdown of the deferred tax asset. The economic effect of this differential is that the ratepayers pay the departure tax, but over time as the deferred tax asset is used to reduce future tax costs. If the ratepayers have $200 million included in rates, but Hydro One uses only $20 million for tax, and takes $180 million from the deferred tax asset, the effect is that the ratepayers have paid $180 million of the departure tax that generated the deferred tax asset in the first place. In the end, the ratepayers will pay the departure tax in full once the full amount of the FMV bump has been used up.[242]

(c) From the point of view of the ratepayers, the fact that they are indirectly paying the departure tax is inherently fair, because they are in the same position as they would have been had no departure tax been payable. The amount they are paying in rates is

[242] This assumes that the tax rates remain the same over the entire period. While this is unlikely, it is unnecessarily complicated to try to include in this analysis the impact of changes in tax rates on the deferred tax asset, and on therefore the equivalence of the ratepayer payments with the original departure tax. If tax rates go up, the deferred tax asset will increase, because the value of the additional deductions created by the FMV bump will increase. Since Hydro One will be recovering actual tax amounts in rates (which will be higher than current tax amounts assumed), this will result in over-recovery of the departure tax from ratepayers. Conversely, if tax rates go down, the deferred tax asset will decrease, and there will be under-recovery of the departure tax. If this analysis were to be done, factors such as the time value of money, the application of Ontario minimum tax, and many others, would have to be included in the analysis. SEC believes that this would quickly lose sight of the underlying principles, and is not a necessary element of the discussion today.

the same. The only difference is that they are paying an amount that is labelled as tax, and otherwise would have been for tax, but is now being used to finance the departure tax over time.

(d) The transaction by which the Province bought more shares is a separate and unrelated transaction, designed in essence to increase the value of Hydro One shares for IPO purposes. The fact that the money was given back to the Province in the form of a tax payment doesn't affect the internal logic of the departure tax, and its ultimate payment by ratepayers in annual instalments.

5.2.5 The essence of this way of looking at the transaction is that the departure tax and the deferred tax asset are a paired set of transactions, offsetting each other. The issuance of shares to the Province is not fundamentally part of that set of transactions, because the fact that the money was used to pay the tax was coincidental, not causal.[243]

5.2.6 The one weakness of this approach to the issue is revealed if you look at this from a simple accounting point of view. The three transactions are not neutral with respect to book value or the value of the shares:

(a) The payment of the departure tax reduces the book value, and presumably the fair value, of Hydro One's shares by $2.6 billion. This will be a reduction to retained earnings.

(b) The creation of the deferred tax asset[244] increases the book value, and presumably the fair value, of Hydro One's shares by $2.6 billion. This will increase retained earnings. At this point, the value of Hydro One's shares has not changed. This stands to reason. The departure tax and deferred tax asset are mirror images, and reflect the fact that the whole tax transaction is ultimately just a timing difference. Both the tax rules, and the

[243] See Tr.11, p.28 et. seq.

[244] Technically, this represents the reduction of a deferred tax liability in part, and the creation of a deferred tax asset in part: see J11.1. However, for this purpose that distinction is irrelevant. It will be relevant on a different view of the situation, in Section 5.5 below. Throughout this analysis, when we discuss the creation of the deferred tax asset, it is really shorthand for the combination of reducing the existing liability, and creating a new deferred tax asset for the balance. Except when the liability and asset are looked at differently, as in Section 5.5 below, the effect of the two descriptions is identical for all relevant purposes.

accounting rules, intentionally treat this transaction as value-neutral.[245]

(c) The issuance of shares to the Province increases the book value, and presumably the fair value, of Hydro One's shares by $2.6 billion by increasing the shareholders equity. There is no corresponding decrease in value. This is a net increase in the series of transactions, overall.

5.2.7 Hydro One will argue that this weakness is incorrect, because the valuation of the shares was done on a discounted cash flow (DCF) basis, so the accounting entries and changes in book value had no impact on share value. That argument, however, is not correct.

5.2.8 It is true that the payment of the departure tax, and the issuance of shares, have no impact on a DCF valuation. On the other hand, the FMV bump, which creates the deferred tax asset, does have a DCF impact. Future revenues without the FMV bump include an assumption that tax is included in rates, but then that tax is paid, so there is no net cash to the company. Future revenues with the FMV bump (and thus deferred tax asset) include the same assumption that tax is included in rates, but then that tax is not paid, so the combination is a net increase in cash and thus DCF value.

5.2.9 Put another way, the only way the DCF valuation of the shares is the same with and without the FMV bump is if it is assumed, with the FMV bump, that only the actual tax payable is included in rates. Then the DCF valuation would be the same before and after the transactions. That is not consistent with the Hydro One view of the transactions.

5.2.10 Notwithstanding this weakness in the Hydro One argument, it remains a reasonable approach to the series of transactions in question. ***If the Board accepts the assertion that Hydro One***

[245] It is interesting to note that, after a lengthy back and forth in cross-examination at Tr.11:19-27, during which the Chief Financial Officer of Hydro One insisted that the accounting entries for the departure tax and the deferred tax asset were enormously complicated, J11.1 was filed showing the very simple entries, and showing that the result SEC posited – no impact on the equity component of the balance sheet – was precisely the case. When Mr. Vels said on p. 27 *"I am sorry, Mr. Shepherd, but you are asking questions verbally that are very detailed, very complex, and I don't feel without preparation, that I am in a good position the answer them"*, it would appear that he was simply trying to avoid admitting that the tax and the asset balanced each other out. Further, when Mr. Vels said, at p. 39 of that same transcript, that the payment of the departure tax reduced the retained earnings of the company, that was misleading. It only reduced the retained earnings, and therefore the book value of the shares, for the one nanosecond until the deferred tax asset was created. As is clear from J11.1, the actual result of the transactions would have been to increase the shareholders equity by a relatively small amount, $19 million, the difference between the departure tax and the deferred tax asset/liability net amount.

actually paid the departure tax, then the fact that the ratepayers effectively pay that tax back over time through an over-collection of tax expense in rates can be justified as fair.

5.3 Following RP-2004-0188

5.3.1 This is not the first time Ontario utilities have had to deal with a fair market value bump. When electricity distributors and transmitters became subject to the PILs regime in 2001, they were deemed to have disposed of their assets at fair market value, and subsequently re-acquired them at the same values.

5.3.2 In RP-2004-0188, the Board had to consider precisely the issue under consideration in this case. The actual PILs payable going forward was going to be reduced because of the FMV bump. The utilities were not going to include the increased asset values in rate base, and were not going to recover depreciation based on those asset values. Therefore, the question arose whether the lower tax cost should be for account of the ratepayers, or for account of the shareholders. The Board determined that the reduction in tax cost should be for account of the ratepayers.

5.3.3 The crucial difference between RP-2004-0188 and the current case, as OEB Staff correctly point out in their Final Argument, is that, in 2001, there was no departure tax payable on entry into the PILs regime. The utilities were already tax exempt entities prior to the changeover, so the deemed disposition did not have any immediate tax consequences. The entry into the PILs regime meant that they became taxable, but in Ontario only (still exempt federally), and thus the tax impact was only on a go-forward basis.

5.3.4 If Hydro One actually paid the departure tax, then OEB Staff may be correct that RP-2004-0188 is not applicable here. If Hydro One did not really pay the departure tax, then prima facie RP-2004-0188 applies just as much now as it did then, and the benefit of the future tax reductions should accrue to the benefit of the ratepayers.

5.3.5 The issue, then, becomes one of form vs. substance. If the transactions are looked at from a substantive point of view, one could characterize them as follows:

(a) Hydro One technically owed a departure tax of $2.6 billion, but the Province determined that it would not require payment of that amount.

(b) To achieve that result, the Province purchased $2.6 billion of shares in Hydro One. Before the purchase, the Province owned 100% of Hydro One, and after the purchase the Province still owned 100% of Hydro One. Thus, in substance all the Province did was to give Hydro One $2.6 million. This is financially equivalent to handing the tax money back to the company, i.e. not charging it at all. The money just circulated back and forth.

(c) Whether the Province gave back the tax money, or not, the FMV bump would still have arisen, as it happens under the federal *Income Tax Act* independently of the departure tax. The deemed disposition under the Electricity Act, which generates the departure tax, is not the same as the deemed acquisition of the same assets under the *Income Tax Act*. They happen at roughly the same time[246], but they are not connected to each other. If the Province had simply waived the tax – which is effectively what they did – the FMV bump under the *Income Tax Act* would still have happened, and the deferred tax asset would still have been created in exactly the same way.

5.3.6 This characterization of the transactions is based on focusing on the substance of the transactions, rather than their form. Prior to the "payment" of the tax, the shareholders' equity of Hydro One was $X. After the apparent payment of the tax, and issuance of new shares for $2.6 billion, the shareholders' equity of Hydro One was still $X, completely unchanged. These two transactions thus have no net impact.

5.3.7 Then, once the company becomes subject to tax under the federal *Income Tax Act*, there is a deemed acquisition of the assets for the purposes of that Act at fair market value. This causes the creation of a $2.6 billion deferred tax asset, and a resulting increase in the shareholders' equity of Hydro One of that amount.

5.3.8 Although the details are different, in substance this is identical to the situation in RP-2004-0188. A utility doesn't have to incur a cost, but gets a tax benefit in the future. In those circumstances, since all of the assets in question are assets used to provide a regulated service, the cost-free tax benefit that arises because of those assets should be for the benefit of the ratepayers.

[246] Not exactly, but close.

5.3.9 We note our earlier analysis of the DCF value implications of this economic reality:

(a) Without the FMV bump (i.e. before any of the transactions), a DCF valuation of the shares will include the full estimated tax on both the revenue and expense sides, so there will be no net cash flow implications of that tax. If tax is $200 million, it is assumed that $200 million is included in rates, so the net cash each year is zero.

(b) With the FMV bump under the *Income Tax Act*, there is a net positive cash impact on the DCF valuation of the shares. If the tax included in rates is the same $200 million, but only $20 million is payable, the DCF valuation will be increased by the net present value of $180 million per year of additional net cash as long as the FMV bump continues to make a difference.

(c) The only way to make the DCF value of the shares the same before and after all of the transactions, including the FMV bump, is to include only the actual tax payable in rates. If the actual tax is $20 million, and $20 million is included in rates, the net annual cash is zero, the same as would have been the case before the transactions. Thus, the value of the shares would be the same whether or not the transactions occurred.

5.3.10 SEC notes that this substance over form characterization of the transactions is likely the way a normal person on the street would see it. Many years ago, the British courts created the notion of "the man on the Clapham omnibus"[247], a way to look at issues from a common sense perspective. The ordinary reasonable person would likely say, looking at this situation, that since the Province gave the tax money back, then really Hydro One didn't pay the tax at all. They would say: "After all of this, did the Province have an extra $2.6 billion to pay down the provincial debt? If not, then Hydro One didn't really pay the tax. When you actually pay a tax, the government ends up with more money."[248]

5.3.11 The argument on the other side, and the key weakness of this characterization, is that the Province could have chosen to waive the tax, and it didn't. Hydro One would still have had the FMV

[247] The term was created in 1903 in the case of *McGuire v. Western Morning News*, [1903] 2 KB 100 (CA), by the then Master of the Rolls, Sir Richard Collins, although he did not claim credit for inventing the phrase. It has since been quoted in thousands of cases, in England and in other Commonwealth countries including Canada.
[248] We would like to take credit for this phrase, but it actually came from a non-energy person – although not one on a bus - when we tested this common sense proposition with normal people.

bump, so the deferred tax asset would still have been available to Hydro One to reduce future taxes. While the economic effect of waiving the tax, vs. taking it and then giving the money right back (essentially for nothing) is clearly the same, the Province chose to do one and not the other. Even if you think that substance is more important than form, the Province chose a particular form for this transaction.

5.3.12 The other important weakness of this approach is that, in the RP-2004-0188 situation, the companies were not taxable prior to the transactions. Thus, no taxing authority lost any money when they became subject to the PILs regime. In the current situation, Hydro One was subject to the PILs regime. The shift from that tax regime, to the federal tax regime, meant that the Province will have an actual future loss of tax receipts as a result of the IPO. Part of the tax that would have been paid to the Province under the status quo situation will now, under the IPO, be paid to the federal government instead.

5.3.13 Despite these two weaknesses, those who argue for the substance over form approach to the transactions have a reasonable and supportable position. Hydro One did not, in substance, pay the departure tax. They incurred no real cost for the benefits that will follow, only an "apparent" but fictional cost, and therefore "benefits follow costs" does not assist them.

5.3.14 Once that argument is removed, the more basic principle is that the utility should be allowed to recover in rates the prudently incurred costs of providing the regulated service, plus a fair return on capital employed. The prudently incurred costs only include phantom or notional costs in a limited number of well justified situations. That would not be the case here. The amount to be included in prudently incurred costs would be the actual tax to be paid by the utility, no more, no less.

5.3.15 Therefore, if the Board concludes that in substance the departure tax was not paid, then it is appropriate to follow RP-2004-0188 and include in rates only the tax actually expected to be paid in the test years.

5.4 Distinguish Provincial vs. Federal Tax Impacts

5.4.1 During the course of looking at the true economic impacts of these transactions, SEC has concluded that there are two ways of seeing the situation that no-one has proposed to date. The

first flows from our comments in para. 5.3.12 above, i.e. that the shift from PILs to federal taxation does have a net cost to the Province. Thus, part but not all of the departure tax ends up being a real loss to the provincial treasury over time, and the payment of the $2.6 billion tax, and the return of that money from the Province to Hydro One, does not change that fact.

5.4.2 This analysis starts by recognizing that Ontario utilities are for the most part exempt from tax under the federal *Income Tax Act* because they are 90% or more owned by the province or municipalities.[249] Companies of a similar size to Hydro One, that are not exempt, pay part of their income tax to the feds (about 56.6%, i.e. 15.0%/26.5%), and part of their income tax to the Province (about 43.4%, i.e. 11.5%/26.5%).

5.4.3 In 2001, the Province created the PILs regime which causes those utilities to pay the same amount of tax as they would pay if they were not exempt, but pay it 100% to the Province. From a federal point of view, the companies were still exempt, but the Province wanted to change their economics so that they acted essentially the same as taxable companies.[250]

5.4.4 The previous legal situation still applies, however, which means that once a company under the PILs regime goes below 90% provincial/municipal ownership, the feds want their share of the taxes. The Province, which would in that case lose that percentage of the annual taxes, gets a one-time payment reflecting the taxes on the difference between tax book value, and fair market value, of the assets that are subject to PILs. In substance, this is a rough way of compensating the Province for its loss of future revenues.[251]

5.4.5 On the other hand, the Province doesn't lose all of their future revenues. They only lose the

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[249] *Income Tax Act,* RSC 1985, c1, section 149(1)(d.3)

[250] There was a theory that this would allow private sector companies to compete in the wires business, much as happened in telecommunications industry. It didn't work out that way, but the collateral benefit, which was achieved, is that the Province received revenues that it could use to pay down Ontario Hydro's massive stranded debt.

[251] There is no mathematical connection between the departure tax and the future tax revenues lost, since the increase in value of the assets is not solely a function of the future income from those assets. However, as the value of assets is often related, at least in some respects, to the income that can be generated from them, it is reasonable to treat the departure tax as a prepayment of the future taxes on those assets. If the discounted cash flow from the assets is used to value the assets, and the tax rates are unchanged over time in that calculation, then mathematically the DCF of the future taxes should be close to the amount of the departure tax, all other things being equal. All other things are not equal, so this is theoretical only, but it is a useful way of looking at the relationship to try to come to a principled approach to the current situation.

federal share of those revenues. Although the FMV bump applies to income for provincial tax purposes as well[252], that is just a timing difference. Eventually, the Province will still get its share of all future income of Hydro One. What it will actually lose – in a permanent sense - is the 56.6% share that will now go to the federal government. That is the amount that the departure tax is intended to address, and the actual "cost" to the Province.

5.4.6 This characterization therefore is the same as the last one – no departure tax was actually paid, because the Province gave the money back. It then adds two additional steps:

(a) The shareholder has incurred a cost of this transaction, but the actual cost is the loss of 56.6% of the tax revenues from Hydro One into the future as a result of the entry of Hydro One into the federal taxation regime.

(b) That shareholder cost comes with a benefit, i.e. the deferred tax asset. Part of that benefit effectively repays the shareholder cost over time, and so under benefits follow costs, should go to the shareholder/company. The remainder of the benefit is simply a provincial tax timing difference, and so should go to the ratepayers. Otherwise, the ratepayers would effectively be paying the provincial portion twice.

5.4.7 This characterization has one glaring weakness: the net present value of the taxes lost by the province, and 56.6% of the departure tax, are only theoretically equal (see footnote). It might be possible, with many highly debatable assumptions, to forecast the net present value of the future provincial taxes lost, and how that relates to the valuation of the assets for departure tax purposes, but it would certainly be a contentious calculation. This is complicated by the fact that the data needed to do these complex calculations does not currently appear to be on the record in this proceeding.

5.4.8 The simpler approach is to assume the equivalence of departure tax and DCF of future taxes, and value the 56.6% of future taxes lost by the Province to the feds on that basis. It would follow that Hydro One, in calculating revenue requirement, would calculate taxes as if there had been no FMV bump (as they have in their Application), but would then include only a portion (likely around 56.6% in a typical year) of that calculated amount in revenue requirement. The ratepayers

[252] Subject to Ontario minimum tax, which essentially limits the impact of timing differences but zeroes out over time.

would pay the federal portion of taxes, which the Province has lost forever, but would not pay the provincial portion, since that is only a timing difference and the Province will get that money eventually.

5.4.9 ***If the Board concludes that the departure tax was not in substance paid, but the Province incurred a real cost through the future taxes now going to the feds instead of the Province, the Board could order that the federal component of taxes be included in rates to offset the cost to the Province, but that the provincial portion not be included in rates.***

5.5 Different Treatment of Liability vs. Asset

5.5.1 The fourth and final approach to this issue starts with the recognition that the FMV bump did not actually create a deferred tax asset. In fact, it reduced the existing deferred tax liability by $1.713 billion[253], and generated a deferred tax asset of $937 million.[254] Those two effects have very different tax and accounting implications, and it is reasonable to posit that the position of the ratepayers and the shareholder should be different for the liability reduction, vs. the asset creation.

5.5.2 This characterization of the issue comes from a different perspective than the others. It says, in effect, that the form of the transactions themselves doesn't matter. What really matters is the tax implications, over time, of the FMV bump. This characterization assumes that, since this is a tax issue, only the tax results matter. All that form over substance stuff is not really relevant.

5.5.3 Under this approach:

(a) The existing deferred tax liability (for both transmission and distribution) of $1,713 billion has been reduced to zero. That liability exists because capital cost allowance for tax purposes is often a bigger deduction than depreciation for accounting purposes, when assets are newer. Later, when the assets are older, the depreciation exceeds the CCA, but in theory (and mathematically) both end up amortizing the entire cost of the asset, no more and no less. Thus, timing differences are created. Where there is a

[253] The balance on the audited financials at the end of 2014.
[254] The balance on the audited financials at the end of 2015.

deferred tax liability from this difference[255], it means the taxes in past years have been lower because CCA exceeded depreciation on a cumulative basis. Rates have thus been kept lower, but in the future there will be a crossover of CCA and depreciation, and tax will be higher. The deferred tax liability is the amount of extra future taxes expected to be payable as a result of the timing difference. The FMV bump has the effect of wiping out this future liability, thus benefiting the ratepayers, who would have had to pay those increased taxes in the future. It is thus reasonable that the ratepayers, who got the benefit of the excess CCA deductions in the past, pay the cost associated with removing their future increased tax liability.

(b) A new deferral tax asset of $937 million has been created. This is not the result of any past timing differences, but rather represents the creation of a new future set of timing differences. The ratepayers have not received any benefit for this in the past, and nor has anyone else. In this situation, the principle at play is prudently incurred costs plus a fair return. Drawdowns of this asset are not a real tax cost in the test years or any subsequent years. To the extent, therefore, that this asset is being drawn down, the ratepayers should not pay that amount in tax each year. No actual cost is being incurred.

5.5.4 The strength of this approach is that it recognizes the potential tax cost reduction to the ratepayers, as a result of transactions that will cost the Province money over the longer term, and says that to the extent of that cost that is not a fair result.

5.5.5 The weakness of this approach is that the $937 million is allocated to the ratepayers, even though that too is in essence, a windfall. However, the reason why that is fair is that it will inevitably be a windfall to someone, whether the shareholders or the ratepayers. Just as was the case in RP-2004-0188, where there is a windfall and no principled way to allocate it to the shareholders, in general the Board will allocate it to the ratepayers, because it is a reduction in the cost to serve them.

5.5.6 The most correct way to implement this view of the issue would be to reduce the tax provision to

[255] This analysis assumes the existing deferred tax liability is all or almost all the result of timing differences between CCA and depreciation. We have not been able to determine from the record of this proceeding, or from Hydro One's publicly available documents, whether this is true, but we believe that, for an asset-rich company like Hydro One, it is likely to be true.

zero in the test years, and continue to do so in subsequent years until the combination of drawdowns in transmission and distribution equals $937 million, i.e. until the asset reaches zero. Since the asset is drawn down first, before the liability is recreated over time, this is technically the right answer. Thereafter, the full tax would be included in rates, even though it would not be paid in fact.

5.5.7 From a ratemaking point of view, however, that is not an optimal solution. Ratepayers get lower rates now, but in four to six years face a big increase. In our view, the better approach, if the Board is implementing this approach, is to allocate the annual tax provision pro rata between the liability component, which under this characterization is fairly the responsibility of the ratepayers, and the asset component, which should be for the ratepayers' benefit. The effect would be that the annual tax provision would be reduced by 35.4% (937/(937+1713)) until the deferred tax liability once more reaches $1.713 billion, probably about 20 years into the future.

5.5.8 **Therefore, if the Board decides to look at this issue through a strictly tax lens, it could reasonably conclude that 64.6% of the value of the FMV bump should go to the shareholder, and 35.4% of the FMV bump should go to the ratepayers, through an allocation of the tax provision in those percentages each year.**

5.6 SEC Recommendation

5.6.1 SEC is aware that Hydro One and OEB Staff support the first characterization, in Section 5.2 of this Final Argument. That characterization, driven by regulatory principles and form over substance, would give all of the tax benefit to the shareholders, and would require the ratepayers for more than a decade to pay tax in rates that was not actually payable by the company. However, if the Board concludes that the departure tax was actually paid by Hydro One, this would not in our view be an unreasonable result.

5.6.2 SEC is also aware that the average person on the street would likely support the second characterization, in Section 5.3 of this Final Argument. That characterization, driven by substance over form, would give all of the tax benefit to the ratepayers, and would match the tax in rates to the tax actually forecast to be payable. If the Board concludes that the departure tax was effectively refunded by the Province, this would be a reasonable result.

5.6.3 The third approach depends on the Board concluding that the essence of the departure tax is to compensate the Province for lost future tax revenues. It would therefore allocate the 56.6% portion of the tax benefit that represents the federal tax (the portion lost) to the shareholders, and the 43.4% balance to the ratepayers. If the Board has this view of the nature of the departure tax, this is a reasonable result.

5.6.4 The fourth approach ignores the transactions themselves, and looks only at the tax results. As a result, 64.6% of the tax benefit (the portion arising out of the pre-existing deferred tax liability) would be the responsibility of the ratepayers, and for the benefit of the shareholders. The remaining 35.4% would be for the benefit of the ratepayers. If the Board decides to take a strictly tax-driven look at the issue, this would be a reasonable result.

5.6.5 We also note that either of the third or fourth results would, in effect, accomplish in a rough way, the goals of the other. That is, if the Board chooses the third approach, the additional effect is that the ratepayers bear most of the cost of getting rid of their existing deferred tax liability described under the fourth approach, which may be seen as fair. If the Board chooses the fourth approach, the Province is also compensated (slightly over-compensated, but reasonably close), as described under the fourth approach, for the lost future tax revenues it will experience, which may also be seen as fair.

5.6.6 SEC is not recommending any of these four approaches. All of them are reasonable. SEC believes that the Board has to make some decisions about its own view of the facts, and the principles that should be applied, in order to reach a fair conclusion. Our objective in this Final Argument is to try to set out, in a fair and balanced way, the considerations at play in those decisions. There is no "right" answer, only possible answers that a reasonable regulator could reach based on the facts before the Board.

6 LOAD FORECAST, OPEBS, AND EFFECTIVE DATE

6.1 Load Forecast

6.1.1 SEC has had a chance to review AMPCO's submissions on the issue of load forecast and adopts their analysis.

6.2 Pension/OPEB Variance Account

6.2.1 Hydro One has proposed to maintain its current accounting treatment of its pension and other post-employment benefits ("OPEB"). It currently recovers pensions on a cash basis but OPEBs on an accrual basis.[256] As the Board is aware, the issue of the appropriate treatment of pension and OPEBs is subject to an on-going consultation and will likely produce a general policy on the question.[257]

6.2.2 In the interim, SEC submits 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. Based on the evidence, this would result in a reduction of $27M in 2017 and $25M in 2018.[258]

6.2.3 Board Staff has taken the view that in the interim period Hydro One should be allowed to continue recovering OPEBs on an accrual basis. SEC disagrees for a number of reasons. 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.[259] 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. Lastly, 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 vs. 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.

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[256] C1-4-2; I-1-131 (Staff IR #131)
[257] See *Regulatory Treatment of Pensions and Other Post-Employment Benefit Costs* (EB-2015-0040)
[258] I-1-131 (Staff IR #131)
[259] *Decision with Reasons* (OPG - EB-2013-0321), November 20 2014, p.87

6.3 Effective Date

6.3.1 Hydro One is seeking an effective date for its rates of January 1, 2017. SEC submits this is inappropriate considering it only filed its application on May 31, 2016. SEC believes that it is the responsibility of a regulated utility to file an application for a rate change in sufficient time before the proposed effective date, to allow the Board, acting reasonably, to conduct a hearing and issue a final decision. Filing seven months before the proposed effective date for a two year cost of service application of the size of Hydro One's transmission business is not sufficient. The Board generally requires at least 8 months for standard single year cost of service application.[260]

6.3.2 Hydro One should have filed its application by the end of 2015 or early 2016. In its previous distribution application, it filed in December 2013, a year in advance of its required new January 2015 rates.[261] It would know an application of similar size would require 12 months for all steps in the proceeding to occur, including the time for the decision to be rendered. The Board should set an effective date the earlier of the first month after which the final rate order is used, or 12 months since the filing of the application.

[260] Distributors filing for January 2017 rates were required by the Board to file their application by April 29, 2016. (See Letter from Ms. Walli, Re: Applications for 2017 and 2018 Electricity Rates, December 29 2015)
[261] Hydro One originally filed its application in EB-2013-0416 on December 19, 2013.

7 OTHER

7.1 Costs

7.1.1 SEC hereby requests that the Board order payment of our reasonably incurred costs in connection with our participation in this proceeding. It is submitted that SEC has participated responsibly in all aspects of the process, in a manner designed to assist the Board as efficiently as possible.

ALL OF WHICH IS RESPECFULLY SUBMITTED

Original signed by

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Mark Rubenstein
Jay Shepherd
Counsel for the School Energy Coalition