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BY EMAIL and RESS

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2300 Yonge Street
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August 10, 2018
Our File: EB20170049

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2017-0049 – Hydro One Distribution 2018-2022 – SEC Final Argument

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

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

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

EB-2017-0049

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Hydro One Networks Inc. for an order approving just and reasonable rates and other charges for electricity distribution to be effective January 1, 2018 to December 31, 2022.

FINAL ARGUMENT
OF THE
SCHOOL ENERGY COALITION

August 10, 2010

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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 distribution rates for the years 2018 to 2022 ("test period").

1.1.2 Hydro One is the largest electricity distributor in Ontario. In this application Hydro One is seeking approval for an annual rate increase of 3.4% over each the next five years, including a 6.1% increase in 2018.[1] It is also seeking approval of the cost allocation methodology to set the rates in 2021 for the integration of three previously acquired utilities. As discussed in detail in this argument, the increased revenue requirement proposed, the rates that flow from it, and the integration of the three previously acquired utilities, will not lead to just or reasonable rates for Hydro One's customers.

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

1.1.4 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 have had 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.

1.1.5 SEC has not addressed every issue in this application, but focused on the major components of the application only. Silence on any given issue should not be construed as acceptance of Hydro One's proposal.

1.2 *Overview*

1.2.1 This application comes at an important inflection point for Hydro One. This is the first distribution rates application filed since its initial public offering, and since the addition of a new CEO, management team, and Board of Directors.

[1] Exhibit Q-1-1, p.3

1.2.2 This 'new' Hydro One is supposed to more efficient and customer centric[2], and to some extent that has started to happen. However, how much of this new focus remains has now become uncertain. After the oral hearing concluded, Hydro One's new CEO 'retired', and its entire Board of Directors resigned.[3] All of this was precipitated by the unhappiness of Hydro One's largest shareholder, the Province of Ontario. As the Government of Ontario said in its recent Throne Speech, "it will act swiftly to restore public confidence in Ontario's electricity system — starting with Hydro One."[4] It has already passed the *Urgent Priorities Act*, 2018, which includes as a schedule the *Hydro One Accountability Act*.[5]

1.2.3 In some important ways Hydro One has made significant improvements as compared to when it last appeared before the Board for a distribution application, in EB-2013-0416. At that time the Board rejected its proposed 5 year approach, and sharply criticized its approaches to incentive regulation. The Board therefore approved only a more limited 3 year plan.[6]

1.2.4 Whereas Hydro One has been able to make improvements in certain areas (OM&A, for example), for others it has failed mightily. The results of its capital plan over those three years (2015-2017) can be best summed up as the customers paying more, and getting less.

1.2.5 Hydro One's own forecast cost performance during the test period for this Application sees it getting *worse* as compared to the benchmarking. This is the conclusion of both Hydro One's own expert Power System Engineering ("PSE")[7], and Board Staff's expert Pacific Economics Group ("PEG").[8]

1.2.6 Customers of Hydro One deserve a plan that provides improvements on cost performance, and

[2] Executive Presentation Transcript, p.8-11

[3] http://hydroone.mediaroom.com/2018-07-11-Hydro-One-Limited-Announces-Process-for-Board-Renewal-and-Retirement-of-CEO

[4] https://news.ontario.ca/opo/en/2018/07/a-government-for-the-people.html

[5] *Urgent Priorities Act, 2018*, S.O. 20

[6] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.18

[7] Tr.2, p.88; Exhibit A, Tab 3, Schedule 2, Attach 2, p.6; K2.2, p.7

[8] Exhibit M1, p.31

listens to their clear desire for lower rates. Hydro One has for many years spent money at a rate demonstrably above a reasonable level, and the benchmarking results continue to bear that out. At the very least, the Applicant in this proceeding should have provided the Board, and the customers, with a roadmap showing that they were on a trajectory to acceptable cost levels, and they had a plan to get there.

1.2.7 The Custom IR plan as filed does not deliver on those key goals.

1.3 *Summary of Key Elements*

1.3.1 ***Plan Components.*** SEC accepts that the general structure of the proposed Custom IR plan is reasonable, with the exception of the proposal to have a mid-term adjustment of certain aspects of the plan for 2021 and 2021, and the annual adjustment. The Board should accept the inflation factor (two component), productivity factor (0%), and stretch factor (0.45%) proposed. With respect to the annual rate adjustment, the stretch factor should also be a component of that, and based on the Board's standard benchmarking model, in the same manner as other distributors on IRM.

1.3.2 The Board should also not approve the proposed capital in-service variance account. Since the account creates a perverse incentive to spend and not be efficient, in the long-term is harmful to the interests of ratepayers.

1.3.3 ***Capital.*** The Board should reduce the in-service additions equivalent of Hydro One's proposed capital expenditures by $558M, to account for a number of deficiencies in Hydro One's Distribution System Plan ("DSP"), and its cost performance. Hydro One's proposed investment plan does not meet the expectations of customers as set out in the customer engagement results.

1.3.4 SEC is also concerned that the information that underlies the investment plan and historical spending is based on data that the Auditor General has determined to be inaccurate. Hydro One's own internal audit report confirms this, and note that as of the time of the filing of the application, the data had still not been remediated.

1.3.5 ***Compensation.*** The Board should send a strong signal to Hydro One that its above market compensation is inappropriate, and none of the premium can be recovered from ratepayers. The evidence is that Hydro One is moving further away from the benchmark. The Board should reduce Hydro One's capital expenditures by at least $20.3M in each year of the test period to adjust for compensation overpayments (in addition to the amount set forth above), and its 2018 OM&A by $17.3M for the same reason.

1.3.6 ***OM&A.*** The evidence shows that Hydro One is on pace to spend less in OM&A than it did in 2017, yet this is not reflected in proposed 2018 OM&A. The Board should reduce Hydro One's OM&A by a further $37.1M, in addition to the compensation adjustment.

1.3.7 ***Integration of Acquired Utilities.*** The Hydro One proposal is technically unsound, unfair as between customer groups, and unsustainable in the longer term. The Board should therefore respond to the Hydro One proposal for the Acquireds as follows:

(a) Deny approval to establish the six proposed new rate classes.

(b) Direct Hydro One to commission an external analysis of their acquisition and harmonization strategies, with a view to identifying solutions that are conceptually sound, fair to all customers, both existing and new, and reasonably likely to be applicable to future acquired customers.

(c) Until Hydro One has presented that study to the Board, and a new, reasonable harmonization approach has been approved, continue the current decoupling of the rates of the Acquired from costs by escalating their rates annually, starting in 2021, by the weighted average rate increase applicable to all other Hydro One customers as approved by this Board.

1.3.8 ***Effective Date.*** The Board should approve an effective date no earlier than May 1, 2018. While all of the delay in the proceeding cannot be attributed to Hydro One, it reasonably knew that it should have filed its application at least 4 months earlier than it did.

2 CUSTOM IR PLAN

2.1 *Plan Structure*

2.1.1 The structure of Hydro One's Custom IR application deviates from the Handbook [9] and past decisions[10] in two material respects.

2.1.2 First, Hydro One has chosen to use a revenue cap instead of a price cap as the basis of its Custom IR framework.

2.1.3 It should be noted that even when a distributor such as Toronto Hydro uses a price cap model as the basis for their Custom IR, that is somewhat misleading, since neither approach is a true revenue cap or a true price cap. This is because both involve significant capital that is not really formulaic at all. It is more akin to a cost of service approach that is then simply grafted on to a price cap or revenue cap approach through the use of a C-factor.

2.1.4 While SEC has significant doubts about these approaches, as does PEG, the Board has determined that, at least conceptually, it is an acceptable way to include capital in an IRM formula.

2.1.5 With respect to the specific decision to use a revenue cap approach, Hydro One has said that it is preferable since it allows them to incorporate the three acquired utilities in 2021.[11] SEC agrees that this is a reasonable approach considering the circumstances[12].

2.1.6 Generally, SEC is of the view that a price cap approach is preferable to revenue cap, since it accomplishes the Board's goal of decoupling revenue from costs. It also tracks more closely a distributor's sales levels, as measured in changes in customer count and volumes.

2.1.7 However, since Hydro One is fixing its load and customer forecasts (i.e. sales volume) for the

[9] *Handbook to Utility Rate Applications*, October 13 2016 ["Handbook"], p.6

[10] *Decision and Order* (EB-2014-0116 - THESL 2015-2019), December 29 2015, p.6

[11] Hydro One Argument-in-Chief, p.32

[12] We note that, given SEC's proposals with respect to the acquired utilities, the need for a revenue cap to incorporate those customers in the main rate structure in 2021 may not be necessary. See Section 6 of this Final Argument.

first three years, there is still sufficient decoupling for that period. If the Board accepts SEC's recommendation that the load and customer forecasts be fixed now for the last two years as well[13], revenues and costs would effectively be decoupled for the full five years.

2.1.8 Therefore, SEC accepts that the first deviation from the Board's preferred structure, used of a revenue cap instead of a price cap, is a reasonable approach that the Board should approve.

2.1.9 SEC does not support the second deviation. Hydro One has proposed that for 2020 and 2021 it will update two aspects of its rate framework at the same time as it incorporates the three previously acquired utilities (Norfolk, Haldimand, and Woodstock, collectively the "Acquireds") – load forecast, and cost of capital. Both of these are contrary to the Handbook.

2.1.10 The Handbook provides that since the adjudication of a Custom IR application requires significant resources, the Board will not allow "in-term updates except under exceptional circumstances and with compelling rationale."[14] Cost of capital and sales volume (i.e. load forecast) are specifically mentioned as areas in which the Board does not expect updates during the term of the plan:

> The Updates: After the rates are set as part of the Custom IR application, the OEB expects there to be no further rate applications for annual updates within the five year term, unless there are exceptional circumstances, with the exception of the clearance of established deferral and variance accounts. For example, the OEB does not expect to address annual rate applications for updates for cost of capital, working capital allowance or sales volumes. In addition, the establishment of new deferral or variance accounts should be minimized as part of the Custom IR application. [emphasis added][15]

2.1.11 Hydro One argues that it meets the requirement of an exceptional circumstance contemplated by the Handbook.[16] SEC submits that, consistent with past decisions, updates of this nature do not meet that threshold.

2.1.12 In the most recent Ontario Power Generation ("OPG") payment amounts decision, the Board

[13] See section 2.1.9 below.

[14] Handbook, p.27

[15] Handbook, p.26

[16] Hydro One Argument-in-Chief, p. 35

rejected a proposal for a mid-term update to the nuclear production forecast (i.e. the OPG load forecast).[17] In doing so, the Board cited the above quotation from the Handbook, as well as previous statements by the Board in the RRFE Report.[18] Similar to OPG, changes in load forecast for Hydro One for 2021 and 2022 are not exceptional circumstances requiring adjustment.

2.1.13 Similarly, the Board also rejected OPG's proposal for a variance account to track the difference between the imbedded nuclear ROE and actual Board deemed ROE in any given year. The Board found that this approach was "analogous to an annual cost of capital update, and thus inconsistent with the OEB's intentions in the Rate Handbook".[19] Hydro One has gone a step further, seeking to update in 2021 and 2022 not just changes in the Board's ROE parameters, but also Hydro One's cost of debt (long and short-term).[20]

2.1.14 Hydro One's rationale for requiring these updates is the integration of the acquired utilities, and that "to be fair to our customers…we treat it as a fairness perspective that we would update the cost of capital and load at the time".[21] SEC submits that there is no reason cost of capital and load forecast should be treated in a different manner than any other cost that Hydro One has to forecast during the test period, including for the Acquireds. As Hydro One readily admits, it is not seeking to adjust the forecast capital or OM&A for the Acquireds, or for any of its other customers, during the term of the plan.[22]

2.1.15 As the Board said in the Handbook, a "utility that cannot forecast its needs within the five year

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[17] *Decision and Order* (EB-2016-0152 - OPG 2017-2021), December 28 2017, p.144

[18] Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, October 18, 2012, page 19.

[19] *Decision and Order* (EB-2016-0152 - OPG 2017-2021), December 28 2017, p.111

[20] See Letter from Hydro One Re: Transcript Correction, July 6 2018:

> On day 2, page 85, line 27, Mr. D'Andrea was asked if Hydro One's cost of capital update for 2021 was limited to the equity portion of the cost of capital and incorrectly replied in the affirmative. Hydro One is proposing to update both the equity portion and the debt portion of cost of capital (update to long-term debt, and update of short-term debt at OEB deemed rate)."

[21] Tr.2, p.80. This argument in essence suggests that adding 5% more customers is sufficiently extraordinary to require a reset of two main elements for all customers, i.e. the tail wagging the dog.

[22] Tr.2, p.81

term, or does not believe it can operate with this level of uncertainty, should consider whether the Custom IR option is appropriate for its circumstances."[23]

2.1.16 It is not as if Hydro One has no load forecast for those later years. It has full revenue requirement and billing determinant forecasts for all five years, as seen in its proposed 2021 and 2022 cost allocation models[24]. This expressly includes the Acquireds. Hydro One has provided the specific rates for each class for all five years. Those proposed rates and their basis are sufficiently detailed that they can be re-run during the Draft Rate Order stage based on the Board's decision on each element of the plan (revenue requirement, cost allocation, load forecast etc.), as would normally be the case. The only adjustment that would need to be made in a later application would be the annual inflation factor and stretch factor set by the Board. This then allows for a largely mechanistic update that can be done easily, without a complex proceeding.

2.1.17 ***Cost Performance.*** Hydro One's own forecast is that its cost performance will decline during the test period. Hydro One may have improved compared to the benchmark (from where it was previously) but it appears that ratepayers can no longer expect continuous improvement. Based on PSE's forecast, Hydro One's proposed plan will see its performance get *worse* over the five year term of the plan. [25]

2.1.18 Even though it has moved into the 4th cohort by the end of the last rate plan, and has made marked improvement over the last few years, Hydro One's own expert, PSE, forecasts that its costs will still be 22.7% over the benchmark by 2022. When only compared to Ontario utilities using the Board's annual benchmarking methodology, and based on its own scorecard targets, Hydro One itself expects to be back in the 5th and worst cohort by the end of 2022.[26]

2.1.19 Board Staff's expert PEG similarly projects Hydro One's cost performance to decline. Based on its analysis, Hydro One's cost will increase above the benchmark every year of the plan,

[23] Handbook, p.27

[24] See Exhibit G, Tab 2, Schedule 1

[25] Tr.2, p.88; Exhibit A, Tab 3, Schedule 2, Attach 2, p.6; K2.2, p.7

[26] Exhibit I, Tab 1, Schedule SEC-30, p.3; K2.2, p.15

culminating in 2022 with costs that are expected to be 23.3% above the benchmark.[27]

2.1.20 Hydro One was not able to explain adequately why it is appropriate for the Board to approve a plan that includes declining cost performance. In fact, Hydro One's VP of Regulatory Affairs Mr. D'Andrea, who is responsible for the Application, admitted that "this is the first time I have seen these numbers."[28]

2.1.21 The only acceptable answer is that the ratepayers and the Board should not accept worsening performance by Hydro One over the term of its plan. Hydro One's customers expect, and the Board should expect, that Hydro One's performance will improve through the test period. That should be the utility's target, and the Board should make clear that it expects that target to be achieved. This is especially important considering that Hydro One is already a very poor performer. Accepting anything else would be contrary to one of the central themes of the RRF - continuous improvement.[29]

2.1.22 SEC notes that, in this case, this is not just an issue of poor performance continuing. It is a much bigger step for a utility to appear before its regulator and say that it plans to have further declines in its already poor performance. The Board should, in our view, require a highly unusual set of circumstances before it allows a utility to knowingly – indeed, with intent - slide further away from reasonable cost levels. That kind of special circumstances is not evident in this Application.

2.1.23 The Handbook states that for a utility seeking to set rates through a Custom IR, the "OEB would generally expect the custom index to be higher, and certainly no lower, than the OEB-approved X factor for Price Cap IR (productivity and stretch factors) that is used for electricity distributors."[30] Hydro One has set theirs based on PSE's empirical work that will match the

[27] Exhibit M1, p.31

[28] Tr.2, p.89

[29] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach* (October 13 2012), p.2; *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.18

[30] Handbook, p.25

OEB's approved X-factor.[31]

2.1.24 SEC submits if there was ever a situation in which the Board should consider requiring an X-factor higher than what the OEB approved level would otherwise be, it would be in this situation. This is to ensure that enough productivity is built into the plan so that on a total cost benchmarking basis, customers will be better off at the end of the plan than at the start. Something Hydro One's proposal does not provide.

2.2 ***Benchmarking, Inflation Factor, and X Factor***

2.2.1 As noted above, there were dueling expert reports on productivity and benchmarking. Much of the debate between Mr. Fenrick of PSE and Dr. Lowry of PEG (Mr. Fenrick's former supervisor and mentor), revolved around technical issues with respect to econometrics, including in particular the tough judgments that economists make when balancing their professional conclusions with the demands of their clients.

2.2.2 It is no secret that SEC prefers the work of Dr. Lowry, who over the years has done such a thorough and thoughtful job on econometric analysis for the Board and for OEB Staff. Our experience with Mr. Fenrick is that he has often been too willing to reach conclusions that favor his client, rather than those driven by an objective analysis.

2.2.3 That having been said, SEC does not have that particular criticism of Mr. Fenrick in this case. While we for the most part accept the conclusions of Dr. Lowry on the issues on which they disagree, in fact the differences in the conclusions between Mr. Fenrick and Dr. Lowry on the key issues in this proceeding are not that material (although the methodological differences certainly are). Whether Mr. Fenrick's work presents Hydro One in a slightly more positive light is really not important, given the conclusions of both experts.

2.2.4 There are essentially four matters on which the experts provided opinions that need to be addressed[32]:

[31] Tr.1, p.56

[32] The fifth, the C-factor and how it is incorporated into the analysis, is adequately addressed in the OEB Staff argument on this point.

(a) Inflation factor;

(b) Productivity factor (what OEB Staff refers to as the "base X");

(c) Benchmarking with other distributors; and

(d) Stretch factor including annual adjustments.

2.2.5 ***Inflation Factor.*** Both experts proposed the composite inflation factor used by the Board. SEC believes that this is an unnecessary complication compared to GDP IPI, but accepts that it is a reasonable approach.

2.2.6 PEG proposed a different and better measure of the human resources component of inflation, for reasons that SEC finds convincing. However, given that the impact is not really material in this case, SEC believes that OEB Staff's view – i.e. to address this in a generic review of the IRM formula – is a good approach.

2.2.7 ***Productivity/Base X.*** Both experts propose a productivity factor of 0%, although they get to that result in different ways.

2.2.8 PSE concludes that the long run productivity for electricity distribution is -0.91%, which means that electricity distributors' costs increase at just under 1% more than inflation. However, then PSE goes on to accept the Board's general view that it will not accept negative productivity numbers, so PSE recommends zero as the productivity (or BaseX) component of the X factor.

2.2.9 PEG has fairly criticized the PSE study on methodological grounds, and SEC believes that the PSE results (although not their ultimate recommendation) should be discounted by the Board due to those methodological problems.

2.2.10 PEG, on the other hand, concludes that long run productivity for electricity distribution is +0.23% in the US based on its seminal study for Lawrence Berkeley Labs. It also concluded that Ontario electricity distribution productivity is about -0.25%. In the end, PEG accepts the

zero productivity factor proposed by PSE, for much the same reasons.[33]

2.2.11 SEC does not believe that either of these conclusions is correct, at least in the real world. In a statistical sense, they are probably both correct in their own way, and the PEG result is probably the better answer. However, SEC believes that it is contrary to common sense to think that a stable business like electricity distribution, with a plethora of replicable processes, many of which can be automated, cannot exhibit productivity that is better than the economy as a whole.

2.2.12 Notwithstanding that belief, the evidence from the experts in this proceeding is that a 0% productivity factor is reasonable. As much as we may disagree with that, the Board has to make decisions based on the evidence it has before it. That evidence is clear, and SEC accepts that a 0% productivity (BaseX) factor is appropriate in this case.

2.2.13 ***Benchmarking***. We have basically two benchmarking analyses available to the Board – PSE's analysis and the Board's standard benchmarking model - , plus a commentary on the PSE benchmarking analysis by PEG.

2.2.14 The PSE benchmarking analysis has been appropriately criticized by PEG on a number of grounds, of which the most important is an obvious error in representing Hydro One's service territory. The PSE study, partially driven as it is by density considerations, assumes that Hydro One serves large parts of Ontario that it does not, in fact, serve. OEB Staff have discussed this problem in their Final Argument[34], and SEC concurs with their analysis.

2.2.15 The end result of both the PSE analysis and the Board's model is that Hydro One is materially above expected costs, but is currently in the 4th cohort. While they remain among the worst cost performers in the province, and plan to get worse, they have moved from 5th to 4th cohort for the current year.

2.2.16 In this respect, we note the comment by Dr. Lowry during cross-examination by Mr. Vegh:

> DR. LOWRY:…We also have some concerns large and small about the

[33] See discussion between Dr. Lowry and Mr. Vegh: at Tr.11, p.199-201

[34] OEB Staff Submissions, p. 23-26

> benchmarking work that was undertaken, but we came to roughly the same conclusion, and thus I think it's more important for the Panel to be reminded of what the conclusion was, and that is that the company's cost during the upcoming plan is projected to be about 23 percent above a benchmark, and said benchmark is based on average cost performance, and it's not the notion of any notion of superior cost performance. So we are already talking about -- in this proceeding about approving revenue requirement that's well above even average cost standards. [emphasis added] [35]

2.2.17 Given the problems with the PSE study, and the fact that PSE and the Board's methodology end up in roughly the same place, SEC submits that for this proceeding, and the test period, the Board should continue to apply the Board's benchmarking model to Hydro One. When Hydro One next rebases, if it can provide an alternative benchmarking approach that does not have the serious flaws this one did, then the Board can look at it again. Meanwhile, the Board will likely be undergoing a 5th Generation IRM process, and the Board's model may itself evolve. Right now, it is already better than the PSE approach.

2.2.18 ***Stretch Factor and Adjustments.*** SEC has no objection to the 0.45% stretch factor proposed by PSE and accepted by PEG. The facts are clear that, at the current time, Hydro One's benchmarking using the Board's model supports the 4th Cohort designation.

2.2.19 SEC has considerably more concern with the suggestion – proposed by Hydro One and accepted by OEB Staff – that if Hydro One for one year achieves 4th cohort status, it should be assumed to have that status indefinitely. The utility's past history, and the Board's stretch factor policy, do not support that assumption.

2.2.20 In their Final Argument, OEB Staff states:

> OEB staff submits that, notwithstanding these matters, for most utilities, updating of the stretch factor results in no change from year to year. OEB staff expects that this would also hold for Hydro One. As such, a requirement to update the stretch factor annually based on a comparison to an extra-provincial peer group, and possibly other Ontario distributors, would not be warranted. OEB staff therefore considers that Hydro One's proposal to hold the stretch factor constant for the test period is reasonable. [36]

[35] Tr.11, p.187

[36] OEB Staff Submissions, p. 22

2.2.21 This conclusion is inexplicable to us. Nothing in Hydro One's past history says that the company can maintain anything better than "worst in the province" cost performance for more than a short period of time. Further, both PSE and PEG predict that Hydro One's cost performance will decline over the five year test period, relative to benchmark costs.

2.2.22 In SEC's submission, OEB Staff's position, and the Hydro One proposal that it supports, both completely miss the point of the Board's benchmarking-based stretch factor. The Board has developed an IRM model in which utilities have immediate consequences – either good or bad – based on their cost performance. While the impact is modest (for Hydro One, maybe $2 million per year moving from one cohort to the next), the message is clear and immediate.

2.2.23 What we have not heard from either Hydro One or OEB Staff is why that concept of immediate consequences should not apply to Hydro One, just as it applies to every other distributor in the province. If OEB Staff is right, and Hydro One remains in the 4th cohort, good for them. If PEG and PSE are right, and Hydro One's cost performance deteriorates, Hydro One goes back into the 5th cohort, and pays the price. On the other hand, if Hydro One responds to the messages in the Board's decision in this case, and improves their cost performance to the 3rd cohort, they will be rewarded with a lower stretch factor.

2.2.24 OEB Staff's position would imply that not only Hydro One, but all other distributors, should have fixed stretch factors during IRM, since for most of them their cohort does not change. This is not the Board's policy for the other distributors, and there is no reason why Hydro One should be a special case.

2.2.25 SEC submits that Hydro One should adhere to the same standards as the other 60-odd distributors in the province. The Board's standard benchmarking model should be applied to Hydro One each year, just like everyone else. If Hydro One's actual costs improve relative to expected costs, it would be good for Hydro One, and for its customers.

2.2.26 ***Conclusion***. SEC therefore submits that the Board should accept the I factor proposed by Hydro One, and the 0% productivity factor and 0.45% stretch factor the experts have agreed is appropriate at the outset. Then, like every Ontario distributor, Hydro One's annual stretch factor should adjust depending on its costs as benchmarked against other Ontario distributors.

2.3 *Capital In-Service Variance Account*

2.3.1 Hydro One has proposed the creation of a Capital In-Service Variance Account. The account would track the cumulative difference over the test period between a) the revenue requirement associated with actual in-service additions, and b) the revenue requirement of the Board-approved in-service additions, for any capital that is 98% lower than the Board-approved levels.[37]

2.3.2 SEC submits that the Board should not approve the Capital In-Service Variance Account. As designed, while SEC agrees that the account can in theory protect against Hydro One failing to deliver on its approved in-service additions (by more than 2%), it is outweighed by creating perverse incentives that are not in ratepayers' interests in the long-term.

2.3.3 The account only protects ratepayers against aggregate underspending. It does not ensure that the correct among of work gets done, or that the work is done at the forecast cost. If Hydro One does less work, or different work, but the overall cost in doing so is above the proposed 98% threshold, then there would be no amount recorded in the account for disposition to ratepayers.

2.3.4 The account, as designed, incents Hydro One to spend money. It does not incent Hydro One to complete all or most of its capital program. The motivation is to spend the amount that is approved, because the alternative is to return it to ratepayers. This can promote profligacy, rather than efficiency. This could be reflected in higher than necessary unit costs, or completion of work that, in the interests of efficiency, could be avoided.

2.3.5 Generally, penalizing a utility for underspending on capital is contrary to the customers' long term interests. If Hydro One is tracking below its forecast in-service amount due to productivity savings, or because it realizes that certain forecast work does not need to be done after all, the better choice, from the point of view of the customers, is to simply not do the work. If Hydro One does not spend that money, that will lead to overearnings to its benefit

[37] Exhibit A, Tab 3, Schedule1, p.8

during the term of the plan. In 2023, when opening rate base is set to actuals, the benefit of that underspending will accrue to customers in the form of lower rates. For assets that have 40-50 year lives, customers will pay more over the long-term if Hydro One unnecessarily spends the money to ensure it does not have to refund any of it during the plan.

2.3.6 Hydro One's has recognized this, and that is why it says it has set the threshold at 98% in order to reduce this perverse incentive.[38] SEC does not believe it achieves this result. Unless the account is set up to refund underachievement to customers based on unit costs, or based on percentage completion of the substantive work plan (in units, rather than in dollars), this perverse incentive will still occur.

2.3.7 The original purpose of these accounts is also important to note. These asymmetrical in-service addition variance accounts began for Hydro One with the approved settlement agreement in Hydro One's 2015-2016 transmission rates proceeding. The problem that this was meant to address was a previous issue that was plaguing Hydro One's transmission business. It had significantly underspent on its approved in-service additions. Hydro One had a plan at the time to remedy the situation for the 2015 and 2016 rate years, but to ensure that ratepayers only paid for work they actually did, the asymmetrical variance account was created.[39]

2.3.8 SEC has supported such accounts 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.[40] Hydro One's distribution business does not appear to suffer from this problem. In fact, the opposite is true with respect to capital. Hydro One has consistently brought more capital into service than has been approved by the Board.[41]

2.3.9 SEC submits the Board should not approve the account. Hydro One has the ability at an

[38] Exhibit I, Tab 17, Schedule EnergyProbe-14

[39] *Decision and Order* (EB-2014-0116 - THESL 2015-2019), December 29 2015, p.38

[40] See for example EB-2014-0116 (Toronto Hydro Custom IR), EB-2012-0002 (Horizon Utilities Custom IR), EB-2014-0101 (Oshawa PUC Custom IR)

[41] Exhibit I, Tab 33, Schedule AMPCO-52(a), K6.2, p.7

aggregate level to execute a capital budget of its proposed size. The issue with Hydro One distribution has not been its ability to spend money; it has been its ability to spend that money properly. The proposed account if anything provides a general incentive to spend the money, as opposed to look for savings, since any amounts below 98% of the approved amount will be returned to ratepayers. Even if Hydro One is expected to underspend on capital purely due to efficiency savings, its own evidence is that it is not planning on returning that to customers through the account, but to reinvest that money in other capital work.[42]

2.4 ***Earnings Sharing Mechanism***

2.4.1 Hydro One has proposed an earnings sharing mechanism ("ESM"). The ESM would share with customers 50% of earnings above the OEB's allowed ROE in any year of the Custom IR term, above a 100 basis points deadband.[43] SEC accepts this approach, as it is generally consistent with other ESMs that have been approved by the Board.

2.5 ***Fair Hydro Plan***

2.5.1 During the oral hearing, Hydro One was questioned by the Power Workers' Union ("PWU") on why the Fair Hydro Plan[44] had not impacted the investment plan in their application.[45] It was effectively put to Hydro One that it should increase its proposed spending if the customers will not experience a bill impact due to the Distribution Rate Protection ("DRP) program, which for some customers caps the distribution bill.[46]

2.5.2 SEC submits that, from a legal perspective, the Board cannot consider the impact of the Fair Hydro Plan, or any of its components such as the DRP program, in making its decision on just and reasonable rates. The DRP is applied *after* the Board determines rates under section 78 of *the Ontario Energy Board Act*.[47] The DRP program takes the approved distribution rates set by the Board and determines, for those customers prescribed under the regulation, the

[42] Tr.9, p.136

[43] Exhibit A-3-2, p.9

[44] https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017

[45] Tr.1, p.87-94; Tr.4, p.166-168

[46] *Ibid*

[47] See *Ontario Energy Board Act, 1998,* s.79.3; O.Reg 198/17

maximum amount they can then be charged.[48] The rest is to be collected from the government directly.[49] The Board's obligation to set just and reasonable rates is unchanged. The existence of an after the fact government subsidy does not affect what is just and reasonable.

2.5.3 It should be noted that only certain customers benefit from the DRP. Only Hydro One's residential R1 and R2 customers are afforded the rate protection.[50] No non-residential customers, including every school and business in Hydro One's service territory, get any distribution bill benefit. Further, many customers do not get the benefit of <u>any</u> aspect of the Fair Hydro Plan, including the reduction in commodity costs.[51] To consider the Fair Hydro Plan as a reason to allow a rate increase that otherwise the Board would not allow would be especially harmful to these customers, who have no protection under this new regulatory scheme.

2.5.4 The PWU's thesis is, at its root, a shocking repudiation of government policy. The Fair Hydro Plan, which was implemented through the passing of the *Fair Hydro Act*,[52] is designed to ameliorate the cost of electricity by shifting some of that cost from a subset of the customers to the taxpayers. The PWU proposal would remove the ability to ameliorate the cost of electricity, and instead treat the Fair Hydro Plan as extra taxpayer money to increase spending, i.e. a subsidy program for electricity spending, rather than a subsidy program for electricity bills. Sooner or later, someone is going to pay for that extra spending. At no time did the Legislature suggest that the goal of the *Fair Hydro Act* was to increase the cost of electricity in Ontario.

2.6 ***<u>Failed To Meet Previous Targets</u>***

2.6.1 The Board commented in Hydro One's previous distribution application decision that in reviewing a Custom IR application, as compared to a cost of service review, it "intended to be framed more like performance inquiries resulting in multi-year outcome commitments and

[48] O.Reg 198/17, s.4

[49] O.Reg 198/17, s.9

[50] O.Reg 198/17, s.2(3)

[51] https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017

[52] *Fair Hydro Act, 2007*

measures that facilitate year-over-year performance assessment."[53] The results of the previous three years' outcome commitments from Hydro One show that it has failed to deliver on the promises that it made to customers[54].

2.6.2 Hydro One had five work plan metrics, and two customer service metrics, for which it proposed targets to the Board.

2.6.3 Hydro One failed to meet its promises to customers in the four of its five work plan metrics. It failed to achieve its own targets in vegetation caused interruptions, distribution line equipment caused interruptions, number of replaced poles, and number of pole top transformers with PCB oil replaced.[55]

2.6.4 Customer service was even worse. Of the two customer service metrics that Hydro One still tracks, it did not meet its targets for either one.[56] It did not meet its own targets with respect to residential and small business customer satisfaction, or with respect to satisfaction of unplanned outages.[57]

2.7 ***Customer Engagement***

2.7.1 Hydro One undertook a customer engagement exercise in the summer of 2016. The results of its engagement with its various customers could not be clearer. In Hydro One's own words it included the following messages:

(a) "[k]eeping costs as low as possible is customers' top priority",

(b) "maintaining reliable electricity service is consistently a second priority to cost",

[53] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.15

[54] Promises that were, at the time, deemed insufficient by the Board.

[55] Tr.5, p.113-116; Tr.158-160; Exhibit I, Tab 18, Schedule SEC-31; K6.2, p.33-35

[56] *Ibid*

[57] Exhibit I, Tab 18, Schedule SEC-31; K6.2, p.33-35

> ***(c)*** "willingness to accept a rate increase to maintain and improve service level is limited".[58]

2.7.2 Even large customers, who are generally more concerned with reliability, "are not willing to entertain the corresponding rate impact".[59] This was the opposite of transmission, where large, directly connected customers did value reliability higher than cost control.[60]

2.7.3 Armed with that information, Hydro One prepared the investment plan and five year Custom IR application that it presented to its Board of Directors in the fall of 2016. In that submission to its Board of Directors, Hydro One's management presented an application that was based on a recommended Plan "A" planning scenario investment (based on achieving improved reliability), and contrasted that with a second plan that it did not support, Plan "B".[61]

2.7.4 Thankfully, the Board of Directors reviewed the material, which included the summary of Hydro One's customer engagement. They rejected the proposal by senior management, and sent them back to find a more appropriate balance between rates and reliability.[62]

2.7.5 Hydro One returned later that fall and presented for approval a modified version of the previously not recommended Plan "B", which was ultimately approved by the Board of Directors, and is the basis for the Application.[63]

2.7.6 In Hydro One's view, this plan addressed what customers told them[64], and the basis of it was an adjusted investment portfolio "that would maintain overall forecast system reliability at current levels, while continuing to offer discrete power quality and reliability improvements for certain segments of the network".[65]

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[58] Exhibit I-3-SEC-4, p.4; K2.2, p.45

[59] Exhibit I-3-SEC-4, p.4; K2.2, p.45

[60] Exhibit I-3-SEC-4, p.4

[61] Exhibit I-3-SEC-4, Attach 1, p.1-

[62] Tr.1, p.79

[63] Exhibit I-3-SEC-4, Attach 2

[64] Exhibit I-3-SEC-4, Attach 2, p.9-11; K2.2, p.51-53

[65] Exhibit A-3-1, p.16; K2.2, p.54

2.7.7 The basis for coming to the number for the investment plan that would ensure overall system reliability, as mentioned, was a rudimentary reliability model Hydro One developed which attempts to forecast changes in reliability (SAIDI and SAIFI) in 2022 as compared to the status quo. It did so by estimating the impact of investments made in four of its major areas (poles, stations, the line components and vegetation management), based on their respective historical contributions to SAIDI and SAIFI.[66]

2.7.8 The Board of Directors' intervention on the matter appears to be the first time Hydro One's management actually considered the customer engagement information. Apparently they did not consider it when they were involved in the planning process to develop their original proposed plan.

2.7.9 During the oral hearing there was confusion among the members of the planning panel about what exactly they did with the customer engagement information. For example, Mr. Jesus indicated that the customer engagement information was an input in determining if they should consider a change to the approved investment risk weighting factors.[67] This is because Hydro One's CEO and CFO had reviewed the prioritization criteria and weighting in June 2015, before the engagement activities had begun.[68]

2.7.10 Ms. Bradley, on the other hand, appeared to indicate it was less about the weighting, but more about setting the budget.[69] She testified that Hydro One "used the results when we reviewed that final plan to set the overall envelope and talk about what plan makes sense, given that feedback."[70] Obviously, Hydro One's Board of Directors disagreed that they had done so adequately.

2.7.11 The timing of the various steps in the planning casts doubt that management could have

[66] Exhibit A-3-1, p.16; K2.2, p.54; Exhibit I-3-SEC-4, Attach 2, p.9-11; K2.2, p.51-53, p.10-11

[67] Tr.7, p.125

[68] Exhibit I-24-SEC-36, p.2

[69] Tr.7, p.126

[70] *Ibid*

properly considered customer feedback. Hydro One prioritized and optimized the candidate investments in early to mid-August 2016.[71] It is only on August 18th that Hydro One received the final customer engagement report.[72] Before this important process, where the investments are prioritized and optimized based on risk and budget constraints, all Hydro One had received from IPSOS was identification of "key themes" of the engagement.[73] While that may have provided Hydro One management with the broad view that "cost was number one, reliability was number two"[74], they would have received insufficient information regarding the specifics of those views, and their extent. If this was not the case, then the final report and the detailed questions added little value to the process.

2.7.12 The evidence also reveals that the customer consultation may originally have been planned to be more extensive than was actually undertaken. In the original work plan, there was at least a proposal, if not an expectation, for a Phase 2 which would "validate earlier results and to add any new or additional customer insights."[75] This Phase 2 was supposed to be undertaken in winter 2016/spring 2017, presumably before filing of the application, in effect to provide customers the opportunity to assess the actual chosen plan and comment on it directly. This was never done.

2.7.13 SEC submits that the evidence is clear. Hydro One engaged in extensive customer engagement, but from management's point of view it was about optics, not about truly listening to the customers. Were it not for the intervention of the Hydro One Board of Directors, Hydro One would have proceeded with an investment plan based on prioritization criteria and weighting that were approved prior to the customer engagement process even starting (customer priorities thus being irrelevant), and then actually prioritized and optimized before the customer engagement report had been delivered.

2.7.14 Clearly there is no sense in which management's investment planning is driven by customer

[71] Exhibit I-24-SEC-36, p.2;

[72] Exhibit I-24-SEC-36, p.2 Tr.7, p.29

[73] Exhibit I-24-SEC-36, p.2; Tr.7, p.29

[74] Tr.7, p.29

[75] Exhibit I-23-SEC-35, Attachment 1, p.2; K5.2, p.36; Tr.5, p.64

preferences. Doing what their customers want is not part of that mindset. This has been fully revealed in the evidence before the Board.

2.8 *Impact of System Reliability On the Plan*

2.8.1 The model that Hydro One used to determine the impact of its proposed investment plan on system reliability is flawed and involves outdated information.

2.8.2 The result of the model that was provided to the Board of Directors, and was used to justify the Plan-B modified approach, has patent errors. As demonstrated, the math did not add up.[76]

2.8.3 For example, the model states that vegetation management outages represent 27% of the 2013-2015 SAIDI average of 7.3 hours[77], which is 1.97 hours. The problem is the model actually assumes a vegetation management SAIDI contribution of 1.8 hours.[78] If the correct number (1.97 or rounded to 2) had been used, it would show that even at the time the Board approved Plan-B modified, the correct impact of the plan would not have been a 0% impact on system SAIDI, but a 10% improvement. If the correct information had been provided at the time, Hydro One's Board of Directors may have required a different (smaller) investment plan.

2.8.4 Changes that have been made since the approval of the investment plan have also altered the results of the model. Hydro One fixed the mathematical errors with the updated numbers provided in response to Energy Probe 17[79], but the impacts from the proposed investments on the numbers are still outdated and incorrect.[80]

2.8.5 For example, Hydro One's proposed vegetation management plan at the time of its filings was forecast to reduce vegetation management impact on both SAIDI and SAIFI by 8% by 2022.[81] But, with the new Optimal Cycle Protocol vegetation management plan that was introduced

[76] Tr.7, p.123

[77] Tr.123-124; Exhibit A-3-1, p.16, Table 4; K6.2, p.145

[78] *Ibid.*

[79] Although continuing to claim that the revised numbers would not change their investment plan, which is not consistent with their own investment strategy.

[80] Exhibit I-18-Energy Probe-17

[81] Jt3.10, p.3

after the filing of the application in the fall of 2017, the expectation is that by 2022 there could be a reduction in SAIDI and SAIFI by up to 40% from its previous 10 year average.[82] On a similar basis as the calculations in the updated reliability impact model in Energy Probe 17, that would be a reduction of 39.6%[83] for SAIDI and 50.5%[84] for SAIFI as compared to the 2013-2016 average used in the table.

2.8.6 When one adjusts the model to account for that single change, the result is that Plan B-Modified now forecasts an overall system reduction in SAIDI by 12%, and SAIFI by 9%.[85] This is significantly greater than the plan that was approved by the Board of Directors to keep rates at a level that would "maintain overall forecast system reliability at current levels".[86] Moreover, it is double the improvement in reliability contained in management's originally recommended Plan A. That plan, it may be recalled, was rejected by the Board of Directors as not providing an appropriate balance between cost and reliability consistent with customer preferences.[87]

2.8.7 But even with that correction, the model may not be the most appropriate reliability forecast anymore. In Undertaking J1.1, Hydro One has provided a detailed year-over-year SAIDI and SAIFI forecast. Based on the response to the undertaking, Hydro One is forecasting significant improvements in SAIDI and SAIFI over the test period. It's forecasting that by 2022 it will achieve a 23%[88] reduction in SAIDI and 19%[89] reduction in SAIFI, compared to the 2013 to

[82] Exhibit I-3-SEC-4, Attachment 4, p.2; K6.2, p.137

[83] SAIDI: Based on Exhibit I-24-AMPCO-13, Table 13, the 2013-2016 average SAIDI for tree contract (vegetation management) outages is 2.30. Exhibit I-3-SEC-4, Attachment 4, p,2 forecasts the SAIDI for tree contacts outages to be 1.39. This represents a reduction of 39.73%

[84] SAIFI: Based on Exhibit I-24-AMPCO-13, Table 14, the 2013-2016 SAIFI average for tree contract (vegetation management) outages is 0.51. Exhibit I-3-SEC-4, Attachment 4, p,2 forecasts the SAIDI for tree contacts outages to appears to be approximately 0.25. This represents a reduction of 50.50%.

[85] Results based on directly inputting the above numbers into the response to J6.01, Attachment 1, Part C, cells H10 and H25

[86] Exhibit A-3-1, p.16; K2.2, p.54

[87] Plan A was to have a SAIDI benefit of 6% and SAIFI of 4%. See Exhibit I-3-SEC-4, Attach 2, p.8; K2.2, p.50; Exhibit A-3-1, p.16-17; K2.2, p.53-54

[88] SAIDI: 2013-2017 average of 7.5/hrs, 2022 forecast of 5.76/hrs (J1.11, p.3, Figure 2)

[89] SAIFI: 2013-2018 average of 2.5/hrs, 2022 forecast of 2.02/hrs (J1.11, p.3 Figure 2)

2017 average.[90]

2.8.8 Much of the improvement is caused by the new vegetation management program, augmented by a proposed 20% reduction in defective equipment.[91] Even that may be a conservative forecast, though. The forecast in J1.1 includes a much lower reliability improvement in tree contact outages than the 40% improvement expected in other places in the evidence as a result of the new Optimal Cycle Program.[92] Thus, the 23% and 19% reliability improvements are probably understated.

2.8.9 This is, in theory, a good news story for ratepayers. Hydro One is proposing positive outcomes for its proposed expenditures. Sadly, it is proposing positive outcomes that customers have told them, in no uncertain terms, that they are unwilling to pay for.

2.8.10 In the competitive market, if a company raised its prices to include features that customers were unwilling to pay for, then they would lose market share. In a monopoly environment where customers have no alternative, the Board must ensure that Hydro One considers what trade-offs between reliability and rates customers are willing to make. Customer engagement is intended to do just that.

2.8.11 When a company is providing goods or services to the public, it is critical that it listen to the customers, and provide what the customers want to pay for. Hydro One was told by its customers (and its Board of Directors) to prioritize cost containment over improving reliability. Instead, they come before this Board (as the proxy for their customers) with a plan to increase costs substantially, in order to deliver reliability improvements.

2.8.12 This therefore raises the question of whether the proposed investment plans can be scaled back to lower the proposed rate impacts on customers. Hydro One's Board of Directors approved a plan that maintained system reliability, and had a rate increase intended to achieve that. Yet,

[90] J1.11, Figures 1 and 2.

[91] Tr.8, p.42-43

[92] See for example, Exhibit I-3-SEC-4, Attachment 4, p.2; K6.2, p.137

the proposed plan actually improves reliability in a substantial way. Hydro One never went back to its Board to determine if it should modify the plan to lower rate impacts, based on new information on the outcomes.[93]

2.8.13 In Section 3 of this Final Argument, SEC has proposed a number of reductions in the capital plan, totaling in aggregate $558M. SEC submits that, with those reductions, the capital plan will still deliver improvements in reliability, but at a much lower level. Those reductions will bring the capital plan more in line with the balance between cost and reliability that the customers said they want, and that the Hydro One Board of Directors approved for submission to this Board.

[93] Tr.7, p.137-138

3 DSP & CAPITAL PLAN

3.1 *Overview*

3.1.1 Hydro One is seeking approval from the Board for in-service additions of $3.628Bn during the test period, which represents an increase of 5.4% over the previous five years.[94] On a capital expenditure basis, Hydro One is seeking to spend $3.57Bn during the test period, which represents a 10.4% increase over the previous five years.[95] These are increases after receiving approval in its last distribution rates proceeding for all of its requested capital.[96]

3.1.2 The proposed increase is mostly driven by a significant additional system renewal spending of 28%, which is somewhat offset by a decrease in system access spending (which is a largely non-discretionary category) by 11%.[97]

3.1.3 The evidence demonstrates that the Board should reduce Hydro One's proposed capital expenditures for a number of reasons, including:

(a) Its planning process is flawed;

(b) The capital plan is not consistent with the message Hydro One heard from its customers;

(c) The evidence does not support the level of work proposed;

(d) The unit costs are too high in many areas, and

(e) Given Hydro One's past capital approvals, ratepayers have already had to pay for a considerable amount of the proposed work that is being proposed again in this proceeding.

3.1.4 The Custom IR structure requires the Board to take an especially close look at the utility's proposed capital plan. As PEG commentated in their expert report, since capital is primarily based on a cost of service approach, while OM&A is not, there is an imbalance that "create[s]

[94] Exhibit I-33-AMPCO-52; Tr.6, p.132

[95] Exhibit I-24-SEC-38 (updated June 11 2018); Tr.6, p.131

[96] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.37; Tr.6, p.135

[97] Exhibit I-24-SEC-38 (updated June 11 2018); Tr.6, p.131-132

the perverse incentive to incur excessive capex to reduce OM&A costs."[98] A rigorous review of the capital plan is required, since "[n]otwithstanding the proposed claw back of some capex underspends, Hydro One still has some incentive to exaggerate capex needs since this strengthens the case for a C-Factor and reduces pressure for capex containment."[99]

3.1.5 SEC is proposing that the Board reduce the capital budget for the test period by $507.4M, as detailed in the following sections and summarized in Section 3.6 below.

3.2 ***Previous Over-Spending/Opening Rate Base***

3.2.1 ***Amount of Overspend.*** In Hydro One's last distribution proceeding, the Board approved the proposed capital budget for the years 2015 through 2017 in its entirety.[100] The Board gave Hydro One every dollar requested for capital spending and corresponding in-service additions, even though the Board found deficiencies in the application, including the DSP, sufficiently material to allow approval of only three years instead of the proposed five.[101]

3.2.2 But even though the Board approved its entire request, it was not enough for Hydro One. It seeks to add to rate base an additional $122.5M, representing additional amounts brought into service during the 2015 to 2017 period.[102] This represents an overspending of 6.2%. [103] Unbelievably, Hydro One claimed that these "capital investments have been in line with the OEB-approved amounts."[104]

3.2.3 The amount is not in line with OEB-approved amounts. It is a significant overspend, and should be rejected.

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[98] Exhibit M1, p.37

[99] *Ibid*

[100] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.37; Tr.6, p.135

[101] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.37

[102] While there was much discussion during the oral hearing about there being $105M in-service additions above the approved (for example see Tr.1, p.129, Tr.6, p.155), as confirmed by the response to J1.3, that refers only to the 2015 difference. The total difference over the previously approved 3 years is 122.5M (See Tr.6, p,132-134; Exhibit I-33-AMPCO-52)

[103] Tr.6, p.134

[104] Tr.6, p.123

3.2.4 As the Board moves towards a more outcomes-based approach to rate-setting, in which it sets spending envelopes and does not approve projects one by one, the Board and ratepayers should be able to expect that, absent some extraordinary circumstances, a utility should live within its means. Spending otherwise is simply imprudent. In Hydro One's case, the Board provided it with a reasonable level of funding – an amount that was equal to what Hydro One requested.

3.2.5 If the Board does not disallow this overspending as imprudent, then all a utility is doing by overspending is foregoing the short-term collection of a small amount of revenue requirement in order to achieve substantial long term revenues[105]. Considering that the lives of many of these assets are over 40 years, two or three years of revenue requirement is a small sum relative to the return on the assets, and the depreciation of the assets, for the remaining depreciable life[106].

3.2.6 The Board should send a strong message that this practice is unacceptable by treating the overspend from a detailed Custom IR budget as imprudent in the absence of clear evidence of extenuating circumstances[107].

3.2.7 ***Direct Evidence of Imprudent Spending.*** Further, the Board should reject the inclusion of this additional amount in rate base because there is direct evidence of imprudent spending. Hydro One's evidence is that the excess spending is primarily due to higher than forecast spending on storm damage and trouble calls.[108] However, even if one assumes that all of that incremental spending (the amount over the Board approved) was for these purposes, and was done in a prudent manner, there is evidence that other spending was imprudent. As discussed

[105] Tr.1, p.127

[106] At current cost of capital, the total revenue requirement collected for a 40 year asset, over its lifetime, is about 256% of its original cost. Of that, about 9.8% of that revenue requirement is collected in the first three years. The remainder, 90.2%, is collected in the remaining years. Overspending by Hydro One in 2015 costs customers 90.2% of the revenue requirement for the overspend. Overspending in 2016 costs customers 95.1% of the revenue requirement, and overspending in 2017 costs customers 98% of the revenue requirement. In the long term, the $122.5 million of overspending by Hydro One from 2015-2017 would cost customers $280-$300 million if approved by the Board.

[107] Of which there is none in this proceeding.

[108] Exhibit D1-1-2, p.2; Tr.6, p.135

in further detail in this argument (see section 3.4**)**, Hydro One executed its approved spending in an imprudent manner.

3.2.8 The evidence shows that most of the renewal work Hydro One did do was at a higher cost that forecast. If Hydro One had done its work at expected cost levels, then there would have been funds left over to take into account the additional storm and trouble call work that was required.

3.2.9 The assets that Hydro One did replace within its system renewal (previously called 'sustainment') spending were negatively impacted by significant data integrity and other issues identified by both the Auditor General and the company's own internal auditors. While the extent of this may never be known, the evidence is that due to the data integrity as well as risk assessment flaws, Hydro One made sub-optimal asset replacement decisions.

3.2.10 SEC submits Hydro One should not be able to recover through opening rate base for additional capital additions above the Board-approved levels for 2015-2017, particularly when some of its capital spending during that period was imprudently incurred.

3.3 ***Planning Process***

3.3.1 The evidence reveals that there are significant issues with Hydro One's planning process. This includes issues related to both the selection of candidate investments, and the optimization process.

3.3.2 Hydro One's investment planning process and asset strategies have not materially changed since its last application, with the exception of vegetation management.[109] The central component to selecting and creating candidate investments is the needs assessment stage of the planning process.[110] At this stage, Hydro One reviews its asset, system and customers' needs to determine potential investment options to develop.[111]

[109] Exhibit I-24-SEC-45; K6.2, p.16; Tr.6, p.170

[110] Exhibit B1-1-1, DSP Section 2.4, p.2 K6.2, p.9; Tr.6, p.161-162

[111] Tr.6, p.161

3.3.3 The basis for the determination of its asset needs is the data that Hydro One has collected regarding those assets, such its age, condition, performance, and utilization.[112] Key then to determining asset needs is ensuring that Hydro One has the proper data to use in its assessment. Without complete and accurate data on its assets, it cannot determine with any precision its needs. It also uses that asset information to determine the baseline (current) and residual (once the asset work is completed) risk levels as part of the risk assessment process.[113] This risk assessment process is central in the optimization and prioritization process.

3.3.4 The evidence is that Hydro One's asset information is inaccurate.

3.3.5 ***Auditor General and Internal Audit Report.*** In its last distribution application, Hydro One presented to the Board, in support of its capital plan, its new asset analytics tool. The then CFO Mr. Struthers told the Board that "to ensure that we are spending money in the right areas, we have made investments to provide us with full visibility to our assets, their condition and our work program".[114] The key way Hydro One was accomplishing that was this: "[t]ools such as asset analytics are allowing us to make targeted investments to minimize the impact of costs to customers and provide us with efficient ways to manage programs and investments."[115]

3.3.6 Mr. Smith, the then Sr. VP of Engineering and Construction, told the Board that with respect to its pole replacement program (that it was proposing to ramp up), "[d]riving this program is the intelligence we have in programs like asset analytics, a portion-by-portion analysis of the province, knowing the age of our fleet of wood poles, knowing where the risk, and knowing where we want to focus on getting those poles replaced". [116]

3.3.7 The new asset analytics program was such a key part of their planning process that they even

[112] Tr.6, p.162

[113] Tr.6, p.170-171; Tr.8, p.140

[114] EB-2013-0416, Issues Day Transcript, p.10; K6.2, p.93

[115] *Ibid*

[116] EB-2013-0416, Issues Day Transcript, p.21; K6.2, p.99

showed a video during the hearing to demonstrate it. [117] While the asset analytics information was not the only tool that planners used, it was an important one. As Mr. Brown, the then VP of Distribution, said to the Board, "[p]lanners actually do the asset risk assessment themselves, though based on the asset analytics information in combination with a bunch of others."[118]

3.3.8 The problem was that the integrity of the data within the asset analytics program had significant issues. In December 2015, the Auditor General of Ontario released her 2015 Annual Report, in which she reviewed Hydro One's operations.[119] Central to a number of the findings and recommendations is the problems with the asset analytics program.

3.3.9 The Auditor General found that information was both incomplete and erroneous, and recommended that Hydro One "ensure the information can support its asset replacement decision making". [120] Regarding the quality of data for its distribution assets, the Auditor General recommended an improvement in that quality, so that "management decisions on replacing distribution system assets are made using reliable and complete information."[121] The Auditor General further recommended that "Hydro One should take actions needed to ensure its Asset Analytics system provides, timely, reliable, accurate and complete information on the condition of its assets".[122]

3.3.10 The Auditor General also specifically recommended that one purpose of this change would be to ensure the Ontario Energy Board can do its job. The Auditor General recommended that "Hydro One should ensure that its applications to the Ontario Energy Board for rate increases include accurate assessment of the condition of its assets."[123] This has not happened.

3.3.11 In its March 2017 Internal Audit Follow-up Report to the Auditor General, the findings show

[117] EB-2013-0416, Tr.4, p.105-118; K6.2, p.105-0118; EB-2013-0416 K4.4, p.7; K6.2, p.87

[118] EB-2013-0416, Tr.4, p.119; K6.115; EB-2013-0416 K4.4, p.6; K6.2, p.86

[119] Exhibit A-3-1, Attachment 3, p.2; K6.2, p.57

[120] *Ibid*, Appendix A, p.5; K6.2, p.57

[121] *Ibid*, Appendix A, p.8; K6.2, p.62

[122] *Ibid*, Appendix A, p.8; K6.2, p.62

[123] *Ibid*, Appendix A, p.8; K6.2, p.57

that as it relates to distribution information, the work is at best on-going, and may have not even begun. The report finds that the asset analytics data remediation efforts that had taken place "were primarily focused on the transmission data (due to the timing of the transmission rate filing) but did not adequately address distribution data integrity issues".[124] The remediation efforts "had not yet addressed the data quality of distribution data at the time of our follow-up".[125]

3.3.12 A further internal audit dated September 2017, following up on a 2015 review of the investment planning process, found that they "continue[d] to identify and correct issues with Asset Analytics input data and risk factor algorithm that will affect the degree to which output results can be used to influence investment decisions".[126] This was rated a "high risk". Further, the asset analytics data issue, which in 2015 was initially assessed at a high risk, remained at that level in this follow-up report some two years later.[127]

3.3.13 The formal audit opinion was that:

> Management has made significant progress in addressing the control deficiencies that we identified and documented within the 2015 audit report, however further progress is needed. Based on the specific areas reviewed, **we concluded that control improvements are needed** to effectively identify, develop, prioritize and select investment plans in support of the Hydro One six-year business plan and the work program. [emphasis in the original][128]

3.3.14 The investment planning follow-up audit explained the risk of the faulty asset analytics program. As the internal audit explained, "t]he absence of well-understood and quality asset information increases the risk of inadequate asset need assessment which can result in diminished confidence in the process involving the AA tool and the potential for less optimal decisions."[129]

[124] *Ibid*, Appendix A, p.8; K6.2, p.57

[125] *Ibid*, Appendix A, p.8; K6.2, p.62

[126] JT.3.2, Attachment 2; p.2; K6.2, p.125; Tr.7, p.46

[127] JT.3.2, Attachment 2; p.1; K6.2, p.124

[128] JT.3.2, Attachment 2; p.3; K6.2, p.126; Tr.7, p.47

[129] JT.3.2, Attachment 2; p.7; K6.2, p.130; Tr.7, p.47

3.3.15 In addition to issues with the asset analytics tool, the investment planning follow-up audit also commented that there continued to be issues related to the risk assessment matrix. The risk level for this problem remained at medium from the initial report in 2015, as the new risk assessment matrix had been developed for transmission, but not distribution assets.[130]

3.3.16 While Hydro One undertook a risk calibration session as part of its 2016 planning process[131], it is important to note that internal audit found that it only had "moderate success in aligning risks across all investments".[132] In response, Hydro One retained an external consultant to review and recommend a new approach, but that approach has been rolled out for transmission, not for distribution, as the plan was "presently with the regulator and 'frozen.'"[133] For distribution, Hydro One had at that point still not fixed the issue identified by its own internal auditors 2 years earlier, i.e. a year before the planning process had begun for the investment plan that underlies this application.

3.3.17 During the oral hearing, Ms. Bradley commented that the calibration session was one of Hydro One's "[quality assurance] aspects of the investment planning process"[134], and that it "bring[s] people that are planning for different types of work together to talk about how they've characterized risk and make sure it's comparable."[135] The problem is it is clearly not effective, if Hydro One had to retain an external consultant to come in and design a better system.

3.3.18 In fact, while Ms. Bradley may have confidence in the current calibration process, her own staff do not. The same internal audit report noted that "an informal survey of 17 planners indicated that challenges remain related to risk assessment distribution assets".[136]

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[130] JT.3.2, Attachment 2; p.1, and footnote 3; K6.2, p.124

[131] Tr.7, p.26, 28

[132] JT.3.2, Attachment 2; p.9, K6.2, p.132

[133] JT.3.2, Attachment 2; p.9,; K6.2, p.132

[134] Tr.9, p.100

[135] *Ibid*

[136] JT.3.2, Attachment 2; p.9,; K6.2, p.132

3.3.19 The impact of these data and risk assessment issues is two-fold.

3.3.20 First, and most important for the purposes of this proceeding, the investment plan that underlies this application is based on faulty data that has likely led to an inaccurate prioritization of investments. This is consistent with the risk identified by Hydro One's own internal auditors.[137]

3.3.21 Second, the capital work undertaken between 2015 through 2017 was similarly completed based on inadequate asset information and risk assessment. This would have led to "less optimal" asset replacement decisions.[138] Imprudent capital work was likely done.

3.3.22 When presented with all of this information at the oral hearing, Hydro One took the view that none of this had any impact on past investment decisions, nor will it on any future investment decisions.

3.3.23 For example, Mr. Jesus first attempted to explain away the issues. He stated that t]he issue identified by the Auditor General and Hydro One's internal audit group was that what was "was being addressed here was really about some of the supporting factors" and that "from a decision-making process, the data that we need to identify the pole, the bad poles, the bad stations, we've got all that data. It is in [Asset Analytics]. Planners are using that data."[139] With due respect to Mr. Jesus, planners using the asset analytics data is precisely the problem. The data used in the process is known to be faulty, and requires remediation as it contains incomplete and erroneous information.[140]

3.3.24 Mr. Jesus then tried to explain that the internal audit report was not about planning information such as asset condition information, but one of operational information.[141] For example, those in the operating centre need to have access to certain information, and the

[137] JT.3.2, Attachment 2; p.7; K6.2, p.130

[138] *Ibid*

[139] Tr.7, p.38

[140] Exhibit A-3-1, Attachment 3, Appendix A, p.5; K6.2, p.62

[141] Tr.7, p.138

systems are not totally aligned for them to do so.[142] It may be that that is part of the issue, but clearly planning data is the central focus of both the Auditor General's Report and the 2017 internal audit follow-up report on investment planning. Otherwise, both critiques would not be focusing on the risk of poor investment decisions.

3.3.25 The bottom line is that both the Auditor General and internal audit found that replacing distribution assets requires reliable and complete information for the planner. Hydro One does not have that for distribution assets. [143]

3.3.26 Ms. Garzouzi also tried to explain that data issues are not significant, since Hydro One makes most of its "decisions based on conditional data, which is largely complete, and reliability data that we have."[144] In effect, her view is that both the Auditor General and Hydro One's own internal audit department simply have it wrong. They do not understand the reality. SEC believes that the Board should have more confidence in the Auditor General and the Hydro One internal audit department on this issue.

3.3.27 Data issues were also discovered by Navigant/1QC in their benchmarking study with respect to substation refurbishments. They found that Hydro One did not have a formal governance process with respect to data for equipment performance and maintenance data. As a result, the information is not incorporated properly into asset condition scoring and the project planning process.[145] Compared to peer utilities, Hydro One has limited tracking and available data on age and usage history of substation equipment.[146] It does not evaluate this important information when making replace versus repair decisions for switching, protection equipment, and relays.[147]

3.3.28 Hydro One's attempt to explain away the serious issues raised, not just by the Auditor

[142] *Ibid*

[143] Exhibit A-3-1, Attachment 3, Appendix A, p.8; K6.2, p.65

[144] Tr.7, p.49

[145] Exhibit B1-1-1, Section 1.6, Attachment 1, p.ii, 27

[146] Exhibit B1-1-1, Section 1.6, Attachment 1, p.26

[147] *Ibid*

General, but Hydro One's internal audit report, should raise the alarm of the Board. The issues were serious enough that Hydro One's own internal audit group considered them high risk, and the impact of asset quality information is that the asset needs assessment and risk assessment will not be done correctly. Ultimately, it will and has led to "less than optimal investment decisions".[148] Just as Hydro One does not appear to listen to its customers, it also does not listen to its auditors, whether external or internal. This may be a contributing factor to Hydro One's poor cost performance, year after year.

3.3.29 The attempts to dismiss the issue by Hydro One's witnesses as having no impact on investment decisions are in any case simply not credible. Just ask Hydro One's own third-party witnesses. Mr. Buckstaff of 1QC and Mr. Grunfeld of Navigant rightly pointed out, "better information will enable you to do better" [149], and "performance improvements stem from making better decisions".

3.3.30 In its Argument-in-Chief, Hydro One points to JT3.1-11 that shows its percentage of data available for certain assets classes.[150] Insofar as those are considered to be sufficient numbers (in many cases below 90%), the issue identified is not just the how much data it has, but if that data is correct and reliable. Both the Auditor General and Hydro One's own internal audit found that it was not.

3.3.31 In its previous application, Hydro One presented the asset analytics programs as a key tool it uses in selecting investments, but now parties and the Board are supposed to believe that this program has no meaningful impact. Hydro One cannot have it both ways. Either it matters or it does not. And if it does not, then Hydro One misled the Board in its last application, and has wasted significant ratepayer funds on its asset analytics program. If it had little to no impact then why did Hydro One focus at all on fixing the problem for its transmission application? Why did its internal audit group consider the issue to have a high risk level?

3.3.32 The answer is obvious. Hydro One's data issues are significant problem. While the exact

[148] JT.3.2, Attachment 2; p.7; K6.2, p.130

[149] Tr.6, p.89

[150] Hydro One Argument-in-Chief, p.92

impact may be unknown, it is simply not conceivable that it had no impact. Clearly, it had some impact on its investment decision-making over the last few years, and will have some during the plan. The investment plan that underlies this application is based on data that is incomplete and inaccurate, as well as a risk assessment matrix that still has problems.[151] This is a significant red flag when considering the proposed capital plan for the test period.

3.3.33 ***Independent Review of its Planning Process Not Undertaken.*** As part of its response to the Auditor General's report, Hydro One management committed to undertake an independent third-party review of its DSP.[152] Hydro One hired AESI Inc. to conduct the review.

3.3.34 OEB Staff take the position that this review satisfies the Board's expectation that the DSP be reviewed by an independent third party.[153] SEC disagrees.

3.3.35 It is clear that what AESI Inc. was retained to do, and ultimately did do, was very different than what one would consider a true "independent review" of the DSP. As the terms of reference show, AESI was hired to ensure and provide advice on the structure and presentation of the DSP.[154] It was required to help "[s]howcase that Hydro One business planning is based on its business value and strategic objectives", and to "ensure evidence demonstrates alignment between proposed investment levels, customer engagement results, and asset needs".[155] They were, in effect, asked to assist the utility in making the DSP look good.

3.3.36 What they were not asked to do was ensure that the investment plan levels were actually aligned with customer engagement result and asset needs, just that the presentation of the evidence demonstrates it.

3.3.37 Mr. D'Andrea testified that Hydro One retained AESI to ensure that Hydro One met the

[151] Tr.6, p.89

[152] Exhibit A-3-1, Attachment 3, Attachment B, p.12; K6.2, p.69; Tr.7, p.62-63

[153] OEB Staff Submissions, p. 71.

[154] Exhibit I-24-SEC-46, Attachment , p.2; K62, p.78

[155] *Ibid*

Chapter 5 filing guidelines.[156] That explains why Hydro One took the view that a) the AESI evidence was "now a moot point given that the OEB set the Application down for a hearing and in doing so found that the contents of the Application accords with its filing requirements"[157] and that b) comments provided by AESI that were not incorporated into the application "is a matter beyond the scope of this proceeding."[158]

3.3.38 Hydro One did not in fact do an independent third-party assessment of what the Board really cares about with respect to its DSP, not its presentation, but the content within.

3.3.39 Further, Hydro One admitted that it had not done a third-party assessment of its distribution investment planning process that underpins the application.[159] Hydro One did say it is now in the process of reviewing its investment planning process in response to direction from the Board in its most recent transmission application.[160] Ms. Bradley said that the changes that come from that process will be applied to the distribution planning process going forward.[161]

3.3.40 One of the changes that Ms. Bradley did mention was occurring as a result of the review initiated by the Board's transmission decision was that that they are changing the risk factors. Hydro One will now weigh only three factors - safety, reliability and environmental risk - instead of the current 8, with the others acting "more as flags".[162] This will mean they no longer will weigh productivity, customer, financial benefit, shareholder value, and employee

[156] Tr.2, p.109

[157] Exhibit I-24-SEC-46(c); K6.2, p.75

[158] Exhibit I-24-SEC-46(e); K6.2, p.76

[159] Tr.2, p.109; Tr.7, p.68-69

[160] Tr.7, p.106; See *Decision and Order* (EB-2016-0160 Hydro One Tx 2017-18), revised November 1, 2017, p.18:

> The OEB requires Hydro One to complete an independent third-party assessment of its TSP and to file this assessment with its next transmission rate application. This assessment should include Hydro One's asset condition assessment and capital investment planning processes. While this type of assessment is not a standard requirement in similar rate cases, the OEB finds on a case-by-case basis that such an assessment could be beneficial in providing confidence to both the OEB and the applicant going forward.

[161] Tr.7, p.69

[162] Tr.7, p.70

risk.[163] Strikingly, the factors relating to cost have been removed.

3.3.41 This appears to be a pretty significant change. When that was put to Ms. Bradley, she fairly responded that "[w]e are in the process of going through how we are going to use it in this planning process, so I can't speak to the specifics of how it's going to play out over the planning process, because we are just developing it right now."[164] Hydro One does not know what the impact will be at this stage, but clearly based on the brief description for that one aspect, it may be very significant.

3.3.42 It is clear then that the planning process that underpins this application is not best practice, and because of that, Hydro One is in the midst of changing it. It is gone already in transmission. It is in the process of being scrapped in distribution. This Application is effectively the last gasp of an investment planning process that has been shown to be inadequate in many ways.

3.3.43 SEC is not recommending that the Board reject the entire investment plan on this basis, but it should give the Board pause in considering a level of expenditures arising out of an obviously flawed planning process.

3.3.44 ***Optimization.*** SEC submits it is likely that the review will uncover other problems with Hydro One's investment planning process. One of those issues is how it prioritizes and optimizes investments.

3.3.45 Since the vast majority of Hydro One's non-demand investments are program as opposed to project based, the software that optimizes and prioritizes the work plan must determine how much work should be done within a program. For example, since the software does not look at every specific pole that may need to be replaced individually, it must determine the aggregate number of poles that should be replaced as part of the broader pole replacement program.

3.3.46 The problem is that the software only allows for two alternative levels of investment for a given program, meaning that it will determine only one of three levels of spending; proposed,

[163] These are the other factors that Hydro One considers (See Exhibit B1-1-1, DSP Section 3.1, p.277, Table 34; K6.2, p.44)

[164] Tr.7, p.70

alternative #1, and alternative #2.[165] The proposed and alternative levels are predetermined by the planners. This is problematic, as the optimal work within the program may sit between the three predetermined levels that are entered into the software. In fact, it leads to a problem where the planner has the ability to significantly influence the outcome by determining the predetermined investment levels. The optimal level of work is not actually being selected, just the best of three options that may or may not be optimal. A system that could determine the actual optimal amount of work in a program should be used.

3.3.47 Also critical to the proper optimization process is to ensure that there are alternatives provided so that investments are actually "optimizable", both in the amount of work and the timing of when it should occur. As Hydro One testified, a more optimizable plan is preferred and that they "are trying to get that more investments are input that we can optimize to pick the most value."[166]

3.3.48 The problem is that the investment plan Hydro One proposes is not very optimizable. Hydro One's 2017-2022 investment plan, which is the basis of this application, has only 23% of its spending that is optimizable.[167] This is *less* than the previous 2016-2021 cycle (32%), and roughly a third of what Hydro One expects for its 2018-2023 investment cycle (67%).[168] What is being presented to the Board is the least optimizable plan, compared to other Hydro One plans. In effect, more of the plan in this Application is set in stone, which limits the flexibility of the regulator.

3.3.49 ***Contingency.*** Hydro One's builds into its project forecasts (in contrast to program forecasts) a standard 10% contingency for those investments at or below $5M, and a refined risk based contingency that "may vary slightly from the 10%" amount for investments greater than $5M.[169]

[165] Tr.6, p.183, 185

[166] Tr.6, p.189

[167] Exhibit I-24-AMPCO-36(e); K6.2,p.22; Tr.6, p.188

[168] *Ibid;* Tr.6, p.189

[169] Exhibit I-24-Staff-121(a); K6.2, p.47; Tr.7, p.95

3.3.50 Hydro One's evidence is that since 2012 it has refined its estimating and execution so that its usage of the built in contingency has been "reducing our contingency usage from 75% to less than 20% last year".[170]

3.3.51 Hydro One should be proud of its ability to dramatically reduce its usage of project contingency. The problem on a going forward basis is that it has not adjusted its budget to reflect what it actually expects to need for contingency. That amount is far less than the 10% that it builds into its project budget. In 2017, for example, the contingency number would have been 1.9% if it were completely accurate.[171] If one looks at a three year average, which has a declining trend, then Hydro One's project contingency level should be 39% of what it has proposed.[172]Using either contingency amount, Hydro One is significantly over–forecasting its project costs.

3.3.52 When confronted with this, Hydro One response was not that the conclusion was incorrect, but that since projects make up only 18% of its capital budget, the amount at issue is not very large.[173] As Mr. Bowness put it, "we're talking about very small numbers from the big-picture perspective."[174]

3.3.53 SEC disagrees. The application as a whole forecasts to spend $3.57Bn on capital. [175] Projects, at 18%, represent approximately $643M of the total capital budget which includes 10% contingency ($64.3 million). The evidence is that the contingency should be no more than 3.9%.[176]. That represents over-forecasting of $39.2M (on average $7.85M per year), or about 1% of the proposed capital budget. .[177]

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[170] *Ibid*

[171] *Ibid*

[172] 39.3% = average of 2015 (55%), 2016 (44%) and 2017 (19%). See Exhibit I-24-Staff-121(a); K6.2, p.47

[173] Tr.7, p.96

[174] *Ibid*

[175] Exhibit I-24-SEC-38 (June 11 2018 updated); K6.2,p.6

[176] Exhibit I-24-Staff-121(a); p.47; Tr.7

[177] Mr. Bowness provided a rough estimate at the hearing of $30M over the 5 years. See Tr.7, p.101. The actual calculation is $642.6 million (18%) times 103.9/110, to adjust the contingency.

3.3.54 Mr. Bowness' comment reveals a truth about how Hydro One views the amounts it is seeking from ratepayers. Customers paying a few million bucks extra here or a few million bucks extra there is not a big deal. This is an entirely inappropriate attitude, which underlies much of the problems that remain at Hydro One. These amounts do matter, and add up very quickly for ratepayers. The fact that this represents a roughly "1 percent variability" does not mean the amount is immaterial.[178] In fact it is several times Hydro One's materiality threshold.[179]

3.3.55 Ratepayers should not have to pay for this inflated amount. After the adjustments proposed later in this Final Argument, the Board should in addition reduce Hydro One's approved capital expenditures by $7.85M for each year of the test period to reflect the excessive contingency built into project forecasts.

3.4 *Capital Programs and Projects*

3.4.1 Not only did Hydro One overspend between 2015 and 2017 compared to what was approved, it completed significantly less work than it had forecast. The most glaring area is that of system renewal (previously called sustaining capital[180]), which Hydro One is seeking to increase significantly.[181]

3.4.2 In each system renewal project and program, Hydro One did less work in 2015-2017 than it had forecast and was approved in its last application.[182] It undertook fewer transformer replacements, recloser upgrades, station refurbishments, pole replacements, PCB line requirement replacements, and large sustaining initiatives, among others, than forecast.[183]

[178] Tr.7, p.101

[179] Hydro One's materiality threshold is $1M. See Exhibit I-16-CCC-18

[180] Tr.6, p.137

[181] Exhibit I-24-SEC-38 (updated June 11 2018); Tr.6, p.131-132

[182] Exhibit I-24-AMPCO-22; K6.2, p.26

[183] Exhibit I-24-AMPCO-22; K6.2, p.26; Tr.6, p.137

		2015-2017 Approved			2015-2017 Actuals			Variance		
		Cost ($M)	Assets (#)	Unit Cost ($M)	Cost ($M)	Assets (#)	Unit Cost ($M)	Cost	Assets	Unit Cost
	Stations									
S1	Transformer Spares and Replacements	54.3	97	0.5598	33.3	68	0.4892	-38.7%	-29.9%	-12.6%
S2	Mobile Unit Substations	11.9	9	1.3222	4.0	1	3.9724	-66.6%	-88.9%	200.4%
S3	Spill Containment	3.4	6	0.5667	2.6	2	1.3001	-23.5%	-66.7%	129.4%
S5	Recloser Upgrades	4.2	57	0.0737	6.3	27	0.2342	50.5%	-52.6%	217.8%
S7	Station Refurbishments	113.6	112	1.0143	127.6	49	2.6037	12.3%	-56.3%	156.7%
	Lines									
S10	Pole Replacements	288.8	37000	0.0078	250.7	33834	0.0074	-13.2%	-8.6%	-5.1%
S11	PCB Lines Equipment Replacements	17.5	3600	0.0049	1.6	381	0.0042	-90.9%	-89.4%	-13.6%
S12	Large Sustainment Initiatives	115.8	33	3.5091	96.7	20	4.8325	-16.5%	-39.4%	37.7%

Sources: K6.2, p.32; Cost 24-SEC-42; Assets 24-SEC-52

3.4.3 For some of these programs, the difference was very substantial. Going forward, Hydro One's forecasts in a number of the areas are similarly overstated, and include costs for the replacement of assets that customers expected would have already occurred in the previous period, given that Hydro One had been provided with the funds for the work.

3.4.4 ***Station Refurbishment***. In its previous distribution application, Hydro One had forecast to complete 112 station refurbishments between 2015 and 2017, yet it only competed 44% (49).[184] It is not as if Hydro One was required to shift spending to other priorities. It spent 12.3% more in total on substation refurbishments. Hydro One's customers thus have paid more for less.

3.4.5 In this application, Hydro One is seeking approval for funding to complete 73 substation refurbishments over the term of the plan.[185] If Hydro One had actually done the work that was funded last time around, then more than 83% of that work would already have been done.[186]

3.4.6 The substation refurbishment program was not simply one of many programs that it planned to undertake. It was significant enough that substation caused interruptions was one of its four proposed outcome measures related to its capital spending.[187] Hydro One proposed additional funding for substation refurbishment in its previous application to "manage system reliability in the face of demographic and load requirement pressures on the system, and to mitigate

[184] Exhibit I-29-SEC-52; K6.2, p.31

[185] Exhibit I-29-SEC-52; K6.2, p.31

[186] 64 less substation refurbishments that Hydro One did not do during 2015-2017 divided by 77 forecasted for 2018-2022.

[187] Exhibit I-18-SEC-31; K6.2, p.33; EB-2013-0416 Exhibit A-4-4, p.9-10; K6.2, p.40-41

against a growing wave of stations reaching expected service life simultaneously".[188]

3.4.7 Hydro One has blamed this failure on how they forecasted the costs per substation refurbishment. Ms. Garzouzi testified that at the time they did the forecast those projects would be done using modular distribution station. [189] These were forecast to cost about $1M each, but it turned out they "came in closer to $1.9 million and that's why you see the cost being higher."[190]

3.4.8 The "'oops' we under-forecasted" ploy may be an explanation, but it is not a justification for the reasonableness of the costs. This is especially the case when the actual unit cost was not $1.9M per substation refurbishment, as Ms. Garzouzi stated, but $2.6M.[191] This is a 160% increase as compared to what was originally forecasted, not the 90% Ms. Garzouzi tried to portray.

3.4.9 Hydro One also claims that the second rationale for the unit cost increase is that they moved to a station-centric refurbishments approach.[192] The problem with this explanation is that its 2018 to 2022 forecast per station refurbishment is just over $2M.[193] At least on a going forward basis, Hydro One, with proper forecasting of modular distribution stations and its new 'station centric' approach, forecasts a unit cost that is still 30% below what it achieved during its previous plan. This leads to the obvious conclusion that either there was some other reason for the $2.6M unit cost, or the forecast unit cost is also wildly inaccurate and once again Hydro One will deliver less work than planned.

3.4.10 SEC submits that if the Board had accurate unit cost information, it may very well have not approved the entire capital budget, which included spending in this program. In fact, even

[188] EB-2013-0416 Exhibit A-4-4, p.9; K6.2, p.40

[189] Tr.6, p.144

[190] Tr.6, p.144

[191] 2015-2017 substation refurbishment actual costs of $127.6M (Exhibit I-24-SEC-42, Attachment; K6.2, p.27) divided by 49 units (Exhibit I-29-SEC-52; K6.2, p.31)

[192] Tr.6, p.144

[193] 2018-022 Budget of $148.1M for Substation Refurbishment Program (Exhibit B1-1-1, DSP Section 3.8, SR-06 Distribution Station Refurbishment) divided by 73 units (Exhibit I-29-SEC-52; K6.2, p.31)

with the erroneous unit cost forecast information we now know was wrong, the Board was concerned with substation unit costs. In its decision, the Board recognized parties' comments on the issue of substation spending.[194] In response, it directed Hydro One to undertake an external benchmarking study, as well as an internal trend analysis, on station refurbishments.[195]

3.4.11 It was that direction which led to Hydro One retaining Navigant and First Quartile to conduct the station benchmarking study.[196] However, since the time period used for the benchmarking study ended in 2014 (prior to the known 2015-2017 cost control problems), the Board is in no better position to understand the reasonableness of Hydro One's substation refurbishment costs. From all the evidence that is available, the situation appears to have significantly worsened since the study was done.

3.4.12 Hydro One's substation refurbishment cost performance problems are likely caused by some of the issues identified by Navigant/1QC in their benchmarking study.[197] They recommended that Hydro One enhance cost and work competition reporting for individual projects, and implement formal change control processes. Mr. Buckstaff testified that in his opinion without formal change control processes there is a potential for project scope creep.[198]

3.4.13 Unlike the leading practices identified, Hydro One did not report on individual projects, just program costs as a whole across the year.[199] The experts further recommended that Hydro One implement a more comprehensive set of performance indicators, including project cost performance, and assess that against the impacts on reliability, maintenance costs, and overall system health.[200] SEC agrees, as measures such as those would ensure that, consistent with the RRFE, Hydro One is showing the 'value-for-money' with respect to their substation

[194] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.36-37

[195] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.38

[196] Exhibit A-2-2, p1, item 10

[197] Exhibit B1-1-1, Section 1.6, Attachment 1, p.ii, 27

[198] Tr.6 p.90

[199] Exhibit B1-1-1, Section 1.6, Attachment 1, p.26

[200] Exhibit B1-1-1, Section 1.6, Attachment 1, p.27

refurbishment program.

3.4.14 With respect to the proposed station refurbishment expenditures for the test period, they have not be adequately justified at the level proposed. First, even though Hydro One undertook fewer replacements than approved in the last proceeding, it was able to achieve and even exceed its target in its outcome measure (the only one) for substation caused interruptions.[201]

3.4.15 Second, even though Hydro One plans to spend $148.1M over the test period on the program, it has provided very limited information on individual station refurbishment selection process, and similar information.[202] It does not even prepare business cases for individual replacements.[203] Not having such information is not reasonable for a program where each individual refurbishment is approximately *twice* Hydro One's current materiality threshold).[204]

3.4.16 SEC submits that this is an ideal program to reduce expenditures, as Hydro One has shown an ability to complete less than its approved substation refurbishments and still exceed its targets for substation caused outages. A reasonable amount would be to reduce the proposed refurbishments by about 20% (3 refurbishments on average per year).[205] This would reduce the proposed capital plan by approximately $6M a year.

3.4.17 ***PCB Line Equipment Replacements.*** While representing a significantly smaller portion of the capital budget, replacing PCB line equipment is telling regarding Hydro One's performance and credibility.

3.4.18 In its previous distribution proceeding, Hydro One sought funding to replace 3,600 pole top transformers with PCB oil between 2015 and 2017.[206] This program was so important to Hydro One (even though the total cost of the project was only $17.5M for those years[207]), that

[201] Exhibit I, 18-SEC-31; K6.2, p.33-35

[202] See the ISD for this program, (Exhibit B1-1-1, DSP Section 3.8, SR-08)

[203] Exhibit I-25-Energy Probe-51(f)

[204] Hydro One's materiality threshold is $1M. See Exhibit I-16-CCC-18

[205] 73 refurbishments over the test period (Exhibit I-29-SEC-52; K6.2, p.31) x 20% = 15

[206] Exhibit I-29-SEC-52; K6.2, p.31

[207] Exhibit I-24-SEC-42, Attachment; K6.2, p.27

it included it as one of its proposed outcome metrics because of the "public safety issue pertaining to the equipment."[208]

3.4.19 This supposed urgent public safety need, which required Hydro One to ramp up its replacements from zero in 2014 to 2,200 per year by 2017, did not actually occur. In the end, Hydro One replaced only 381 (10.5% of the forecast) pole top transformers due to PCB and zero in 2017.[209] Hydro One again in this application provides the same rationale for the need to do the work, this time ramping up from zero in 2017 to 2,152 transformers in 2018, reaching 3,228 by 2022.[210]

3.4.20 Hydro One is also forecasting to replace these transformers at a significantly higher unit cost than it achieved over the last 3 years. Hydro One replaced those pole top transformers at a cost of about $4,199 each.[211] Based on the current application, the utility is now asking for a budget of $5,646 each.[212] This represents a unit cost increase of 34%. This is entirely unreasonable, and seems to be inflated.

3.4.21 Considering the increased quantity of replacements planned, Hydro should be able to undertake the work at a unit cost that is the same or lower than what it achieved in the past. A 33% average increase is unreasonable and should be disallowed. SEC submits a more appropriate unit cost is a conservative 2% a year increase over the previous 2015-2017 average unit cost. This leads to an overall reduction of $15M over the test period.

[208] EB-2013-0416 Exhibit A-4-4, p.9; K6.2, p.40

[209] Exhibit I-29-SEC-52; K6.2, p.31

[210] Exhibit I-29-SEC-52; K6.2, p.31

[211] K6.2, p.32; 2015-2017 381 units replaced (Exhibit I-29-SEC-52; K6.2, p.31) divided by 1.6M (Exhibit I-24-SEC-42, Attachment; K6.2, p.27)

[212] 2018-2022 program budget of 72.8M(B1-1-1, DSP Section 3.8, SR-08) / 12912 units (Exhibit I-29-SEC-52; K6.2, p.31)

	Actual			Forecast			
	2015-2017	2018	2019	2020	2021	2022	2018-2022
Total Program Cost ($M)	1.6	11.6	11.8	12.1	18.5	18.9	72.9
# of PCB Line Equipment Replaced	381	2152	2152	2152	3228	3228	12912
Unit Cost ($)	4199	*5390*	*5483*	*5623*	*5731*	*5855*	*5646*
Revised Unit Cost (2015-2017 avg esculated by 2% ($M)		4283	4369	4457	4546	4637	
Revised Total Program Cost ($M)		9.2	9.4	9.6	14.7	15.0	57.9
Reduction From Proposed		-2.4	-2.4	-2.5	-3.8	-3.9	-15.0
Sources: Cost ISD SR-08; Assets 24-SEC-52							

3.4.22 ***Large Line Sustaining Initiatives.*** In this program there is a similar pattern to other programs. Hydro One forecast in EB-2013-0416 to complete 33 large lines sustaining initiatives[213] at an average cost of $3.5M.[214] It ended up doing only 20, at an average cost of $4.8M.[215] This represents a 37% increase. SEC submits this is unacceptable.

3.4.23 During the oral hearing, Hydro One tried to brush this off by pointing to the fact that for this program it is more appropriate to measure it in kilometers of lines.[216] SEC agrees that km would be a better measure, but that over the number of projects completed over the 3 year period, the *average* kilometer per initiative in the program budgeted versus actuals should be roughly equal. Any difference would not reasonably lead to a 37% increase in initiative unit cost. It is also the only information that Hydro One has provided. SEC submits the information demonstrates once again Hydro One's poor performance in executing its proposal capital plan.

3.4.24 In the test period, Hydro One is proposing to undertake 55 separate large line sustaining projects at a total cost of $151.8M.[217] This is an average of approximately 18 projects per year, which is more than double the previous 3 year average of 7.5 per year. The proposal is

[213] SEC notes in a number of tables EB-2013-0416 program S-12 is noted as being called 'Large Sustainment Initiative', in some other parts of the EB-2013-0416 it is titled 'Line Sustainment Initiative' or "Large Sustainment Initiative Lines'. It appears it is just different wording for the same program which is a refurbishment of entire feeders of sections of feeders. (See EB-2013-0416 D-2-2-3, S-12)

[214] 2015-2017 forecast program costs of $115.8M (Exhibit I-24-SEC-42, Attachment; K6.2, p.27) divided by 33 forecast units (Exhibit I-29-SEC-52; K6.2, p.31)

[215] 2015-2017 actual program costs of $96.1M (Exhibit I-24-SEC-42, Attachment; K6.2, p.27) divided by 20 actual units (Exhibit I-29-SEC-52; K6.2, p.31)

[216] Tr.6, p.137-138

[217] B1-1-1, DSP Section 3.8, SR-08

unfeasible for two reasons. First, Hydro One's execution performance during the past three years demonstrates that it does not have the ability to ramp up its program to the proposed levels. If it could not undertake 11 projects per year as approved in EB-2013-0416, how can it undertake an average of 18 per year during the test year? Second, the evidence demonstrates that Hydro One does not need to undertake such a significant increase in its large line sustainment program. Hydro One's line equipment contributions to SAIDI and SAIFI have remained relatively stable since 2012.[218]

3.4.25 SEC submits reducing the annual capital expenditures for this program by one-third allows for both an increase in large line sustainment projects during the test year, but at a rate that is more realistic and is more commensurate with its actual reliability performance.

3.4.26 ***Pole Replacements.*** It appears the only major program in which Hydro One unit costs were better than forecast was that of pole replacements. Hydro One was able to replace each pole at about 5% less than what it had forecast.[219]

3.4.27 With that said, even though it was more productive in terms of unit cost, Hydro One completed 3165 less replacements than it had planned.[220] Considering how much time was spent during the last oral hearing discussing the wood pole replacement program, and the fact that in the EB-2013-0416 proceeding Hydro One proposed a metric to track achievement on this program,[221] SEC is once again surprised with the utility's inability to deliver on this supposedly key renewal program. In fact, Hydro One's ability to deliver on its program got *worse* between 2015 and 2017. It was not even able to increase its replacements each year.

3.4.28 SEC has no confidence, then, that Hydro One is able to deliver on a pole replacement program that requires it to increase the annual level of accomplishment from 9,600 poles in 2018, to

[218] See Exhibit I-28-AMPCO-28(a)

[219] See analysis in the table at para. 3.4.2

[220] There appears to be an inconsistency in the numbers provided in response to Exhibit 24-AMPCO-22, Table 1, which shows a difference of 4,224 pole attachments, as compared to 3165 shown in Exhibit I-29-SEC-52. SEC assumed the former is correct as it closer to the 91% achieved that was referenced in the oral hearing by Mr. Bowness (Tr.6, p.160).

[221] EB-2013-0416 Exhibit A-4-4, p.6-7; K6.2, p.38-39

14,300 in 2019, then up to 16,128 by 2022.[222] The Board should only allow a pole replacement program that is marginally higher than what Hydro One has been able to deliver in the past, which peaked at 12,335 in 2016.[223] SEC submits a reasonable goal over time is 14,050 by 2022, which represents an increase of 5% over the previous maximum. Even that is optimistic.

3.4.29 SEC submits the Board should approve a ramp up to a more realistic goal of 14,050 poles a year by 2022. This would result in total reduction over the five years of 13,301 poles.

3.4.30 This approach creates a more realistic pace of pole replacements, but it does not address the broader issue of whether there are ways to avoid the need for this level of replacements altogether.

3.4.31 The Navigant/First Quartile benchmarking report noted that Hydro One was one of the very few utilities that participated (4 of 17) that did not have a distribution pole refurbishment program to address poles that prematurely fail.[224] The primary benefit identified by Navigant/First Quartile is that the cost to replace a pole is 7 times more expensive than to refurbish it.[225] It is why one of the major recommendations in the report is that Hydro One modify its work program "to include a rigorous pole refurbishment option."[226]

3.4.32 More than 20 months after Navigant/First Quartile provided its final report to Hydro One, it has yet to develop a pole refurbishment program.[227] Its evidence is that it is "currently exploring pole refurbishment."[228] Pole refurbishment is not a new idea that requires years of exploration or investigation. The vast majority (13 of 17) included in the study that provided information on pole replacements had such a program. [229] Most of the peer utilities in the

[222] Exhibit I-29-SEC-52; K6.2, p.31

[223] Ibid

[224] Exhibit B1-1-1, Section 1.6, Attachment 1, p.14

[225] Exhibit B1-1-1, Section 1.6, Attachment 1, p.16

[226] Exhibit B1-1-1, Section 1.6, Attachment 1, p.ii

[227] Tr.8, p.28

[228] *Ibid*

[229] Exhibit B1-1-1, Section 1.6, Attachment 1, p.16

sample were other large utilities like Hydro One.[230]

3.4.33 SEC does agree with Hydro One and Navigant/First Quartile that a pole refurbishment program is not a substitute for a replacement program.[231] It may not make economic sense to refurbish a 50 year old pole. A refurbishment program is likely designed to refurbish poles on the younger side that have failed inspection tests and thus are likely to fail. Looking at Hydro One's own evidence regarding the age demographic of poles in poor condition, there are thousands of poles that would fit the criteria of those that are likely to fail prematurely. [232] But, since Hydro One currently just replaces these poles, customers are paying 7 times as much as they should.

3.4.34 Without a refurbishment program, Hydro One is replacing poles prematurely.[233] Hydro One identified 10,000 poles in poor condition that are candidates for refurbishment.[234] This represents approximately 9.4% of the total population of poles in poor condition.[235] Applying that to the proposed replacement of 72,000 poles during the test period[236], Hydro One should be refurbishing instead of replacing 6,768 of those poles.

3.4.35 The Board should therefore further reduce the proposed pole replacement budget to reflect the fact that Hydro One should have a pole refurbishment program in place to avoid some of the replacements it plans to make.

3.4.36 A further concern is the unit cost that Hydro One is forecasting to replace each pole.

3.4.37 The unit costs for pole replacements have been an area of concern of the Board in the past. The Board in Hydro One's last distribution application ordered Hydro One to undertake a

[230] Exhibit B1-1-1, Section 1.6, Attachment 1, p.5

[231] Tr.6, p.13

[232] J7.3, p.2, Figure 2

[233] Tr.6, p.107

[234] Tr.9, p.84

[235] 10,000 divided by the106,000 poles currently in poor condition (Tr.6, p.186, Argument-in-Chief, p.101-102 [67,000 end of life state + 39,000 red pine poles).

[236] J7.3, p.3

benchmarking study to compare its costs against peers, so that it presumably could assess the reasonableness of Hydro One's costs.[237]

3.4.38 The Navigant/First Quartile benchmarking study results indicate that Hydro One unit cost per pole is 16% higher than the benchmark.[238]

3.4.39 Astonishingly, during their examination-in-chief, Mr. Grunfeld on behalf of Navigant, and Mr. Buckstaff on behalf of First Quartile, appeared to walk away from their studies' own findings.[239] Mr. Grunfeld, on behalf of the two of them, told the Board they "want[ed] to provide a caution about pulling specific data out of our report, because of the limitations of the data that we had to work with."[240] They then listed a number of issues with the data, such as inconsistent participation of the peers in providing requested information[241], the small sample size[242], and issues with individual data points.[243] They then concluded by stating that even though they state clearly within the report that based on their analysis Hydro One's pole attachment costs were 16% above the benchmark, they "can't say with statistical confidence that Hydro One's pole replacement cost is different from the mean of the comparison group".[244]

3.4.40 Not a single one of these qualifications is included in their report, nor presented to parties or the Board at any point before the oral hearing. Hydro One itself never provided a view that the Board should discount the findings for any reason. This appears to be a last minute attempt to soften the impact of damaging expert conclusions, and the Board should not bite. The Board should give little weight to this last minute change in testimony.[245]

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[237] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.38

[238] Exhibit B1-1-1, Section 1.6, Attachment 1, p.14

[239] Tr.5, p.135

[240] Tr.5, p.135

[241] Tr.5, p.135

[242] Tr.5, p.135

[243] Tr.5, p.136;

[244] Tr.5, p.136

[245] This may have explained why Hydro One did not qualify either Mr. Grunfeld or Mr. Buckstaff as experts in benchmarking at the hearing.

3.4.41 SEC submits that the Navigant/First Quartile benchmarking results, a study ordered by the Board, is the best information that the Board has on how Hydro One compares to its peers in terms of pole refurbishment unit cost. The problem with taking those results and applying them on a going forward basis is that the data is from 2012 to 2014. One of the concerns SEC had with the study's usefulness is that it is an average of data from 2012 to 2014, and in this proceeding we are looking at forecast costs for 2018 to 2022. That is a significant gap in time.

3.4.42 In addition, the benchmark study collected data slightly differently from how Hydro One reports its pole replacement unit cost. Mr. Bowness testified that the best way to compare the two numbers was to "subtract $130 from those projections in SEC 29, and that would be in line with what would be in the Navigant information."[246]

Pole Replacement Unit Cost									
	2015	2016	2017	2018	2019	2020	2021	2022	2018-2022 Avg
Gross Cost Per Pole ($) per SEC-29	8392	8359	8431	8733	8908	9080	9256	9437	*9083*
Mr. Bowness Recommended Adjustment ($)	-130	-130	-130	-130	-130	-130	-130	-130	*-130*
Revised Gross Cost Per Pole ($)	8262	8229	8301	8603	8778	8950	9126	9307	*8953*
Variance compared to 2012-2014 Benchmark ($7105)	16.28%	15.82%	16.83%	21.08%	23.55%	25.97%	28.44%	30.99%	26.01%
Gross Cost Per Pole ($) per SEC-29	8392	8359	8431	8733	8908	9080	9256	9437	*9083*
Mr. Bowness Recommended Adjustment ($) esculated by 2% per year	-132.6	-135.3	-138.0	-140.7	-143.5	-146.4	-149.3	-152.3	*-146*
Revised Gross Cost Per Pole ($)	8259	8224	8293	8592	8764	8934	9107	9285	*8936*
2012-2014 Navigant/1QC Benchmark of $7105 esculated by 2% per year ($)	7247	7392	7540	7691	7844	8001	8161	8325	*8005*
Variance compared to Benchmark	***13.97%***	***11.25%***	***9.99%***	***11.72%***	***11.73%***	***11.65%***	***11.58%***	***11.53%***	***11.64%***
Source: Tr.9, p.32-33; Exhibit I-18-SEC-29, p.4; Exhibit B1-1-1, Section 1.6, Attachment 1, p.14									

3.4.43 In fairness to Hydro One, Mr. Bowness' approach needs to be slightly adjusted, since it does not account for changes in cost over time to both the $130 difference in approaches and the benchmark. Increasing both those amounts by a 2% escalator (an amount above inflation), leads to a result that Hydro One has likely improved compared to the benchmark, but on average between 2018 and 2022, per pole replacement costs will still be 11.64% too high compared to its peers. This remains unacceptable.

3.4.44 Complicating matters further is that, as explained by Hydro One, the program costs are

[246] Tr.9, p.133

calculated on a 'net basis' as opposed to a gross basis as they do not include the pole removal costs.[247] It is not entirely clear where the removal costs are contained within the application. Because of this, SEC has only applied the proposed percentage reductions on net unit costs contained in the program cost. This has the effect of understating the appropriate proposed reduction.

3.4.45 SEC submits Board should reduce the net unit cost by 11.6% to reflect the premium that Hydro One is asking ratepayers to pay for its continuing and unjustified inefficiency in this area.

	2018	2019	2020	2021	2022	2018-2022 Total
Cost ($M)	73.8	112.1	127.9	131.3	133.9	***579***
Proposed # Poles Replaced	9600	14300	16000	16123	16128	***72151***
Net Cost Per Pole ($)	7688	7839	7994	8144	8302	***8025***
Revised Net Cost Per Pole ($) with 11.6% reduction	6796	6930	7066	7199	7339	***7094***
Revised # Poles	9600	10500	11500	12750	14500	***58850***
Revised Total Cost ($M)	65.2	72.8	81.3	91.8	106.4	***417***
Reduction From Proposed ($M)	***-8.6***	***-39.3***	***-46.6***	***-39.5***	***-27.5***	***-162***
Source: B1-1-1, DSP Section 3.8, SR-09; I-SEC-52						

3.4.46 ***Smart Meters.*** Hydro One plans to spend $79.9M over the test period to replace smart meters (Advanced Meter Infrastructure Hardware Refresh program) that have reached their expected service life.[248] Hydro One has determined that the expected service life for these smart meters is 15 years, but that determination is entirely based on discussions with the vendor.[249] The vendor has an obvious incentive to have Hydro One replace its infrastructure sooner rather than later.

3.4.47 Hydro One claims that since this is a new technology, it cannot determine whether the expected service life is greater than 15 years, or compare the time frame with other

[247] Tr.9, p.34

[248] Tr.8, p.12; B1-1-1, DSP Section 3.8, SR-14; K7.3, p.20

[249] Tr.8, p.14

distributors.[250] Hydro One is not planning to do any independent analysis to determine the health or condition of its meters.[251] It is their view that the meters will simply stop working.[252]

3.4.48 Nor has Hydro One provided any evidence that these meters have a higher than expected failure rate. If Hydro One had studied the failure curves of smart meters from this vendor to date, they might have an indication of the real service life of the assets. Common sense says that the service life is not going to be less than the replacement timing recommended by the vendor, and it might well be longer.

3.4.49 SEC submits this this approach is unreasonable, and will result in ratepayers paying for the retirement of these smart meter assets prematurely. Hydro One plans on spending almost $80M, with all but $1.4M to be spent in 2022 to begin to replace its smart meter fleet.[253]This is a very considerable amount, and Hydro One should be required to ensure that the meters actually need replacing before spending that kind of money.

3.4.50 The Auditor General has in the past criticised the lack of cost/benefit analysis to the smart meter program.[254] Prematurely replacing the meters will unnecessarily add to the cost for ratepayers, and will only compound any past errors with respect to the program.

3.4.51 SEC submits the Board should not approve any spending on a smart meter replacement program during the test period until Hydro One can do the required analysis to justify the expenditures. At this point it has not done so but should be able to for its next Custom IR application with a test period beginning a year later in 2023.

3.4.52 ***Integrated System Operating Centre***. The single largest distribution project is the Integrated

[250] Exhibit I-28-BOMA 25(a); K7.3, p.24; Tr.8, p.14

[251] Tr.8, p.15

[252] *Ibid*

[253] Tr.8, p.12; B1-1-1, DSP Section 3.8, SR-14; K7.3, p.23

[254] Auditor General of Ontario, 2014 Annual Report, Chapter 3, Section 3.11, Smart Metering Initiative <www.auditor.on.ca/en/content/annualreports/arreports/en14/311en14.pdf>

System Operations Centre ("ISOC"), which has a planned in-service date of 2021.[255] The ISOC will house a new backup control centre, a telecom management centre, a data centre, and a security monitoring centre.[256] There are two main problems with this project. First, it continues to increase in cost and scope, without strong justification. Second, there is no approved business case supporting this project.

3.4.53 The ISOC project has increased in cost and scope over time. In the EB-2013-0416 application it was forecast to cost $56.5M[257]. It then increased in scope and cost, so that when this application was originally filed the revised forecast was $130M.[258]

3.4.54 In the midst of the current proceeding, the project cost was revised once again, with a new total cost of $138.4M, with $69.3M allocated to distribution ratepayers.[259] Increases in costs like this should obviously concern the Board, especially considering that Hydro One has a long history of having difficulty controlling costs.

3.4.55 The increasing cost is particularly problematic for a large project that does not even have a supporting business case. Even though Hydro One is seeking approval for inclusion of this project in its rate base, it has yet to develop a business case.[260] It has said that it will not have an approved business case until *after* the Board's decision[261], and also until after the construction RFP is completed.[262]

3.4.56 Hydro One's view in response to questions on this bizarre arrangement was that much of the information contained in the business case is located in the Investment Summary

[255] Tr.10, p.24; Exhibit B1-1-1, DSP Section 3.8, GP 18, p.12 (updated); K10.1, p.9,

[256] Tr.10, p.21

[257] Tr.10, p.21; Exhibit I-29-SEC-61(a); K10.1, p.22

[258] Exhibit B1-1-1, DSP Section 3.8, GP 18, p.12, 23; K10.1, p.20, 21; Tr.10, p.21

[259] Exhibit B1-1-1, DSP Section 3.8, GP 18, p.12, 23 (updated); K10.1, p.9, 16; Tr.10, p.19-20

[260] Exhibit I-29-SEC-61(c); K10.1, p.23

[261] Tr.10, p.27

[262] Tr.10, p.26

Document.[263] That entirely ignores the fact that they are separate documents, developed and used for separate purposes, and operating under different levels of analysis and rigour. Hydro One's own Program and Project Approval Procedure guide discusses the contents of a business case - which is an operational document - and they include important elements that differ from the Investment Summary Document, which is a regulatory document.[264]

3.4.57 If a business case is essentially just the same as the Investment Summary Document, then what is the point in having an elaborate process for business case development and approvals, if they have no real impact? The answer appears to be that Hydro One believes the Board's decision to approve the spending of ratepayer funds on a major project such as this requires less information, analysis, and rigor than management's decision to approve the spending of those same dollars internally. SEC does not agree.

3.4.58 While Hydro One may be waiting on the Board's decision in this case to develop a business plan for the ISOC (or, at least, one it considers in a proper state to share with the Board), it is not waiting on the Board's decision before spending money. It will have spent approximately $16M ($8M allocated to distribution) before 2018 even began[265], including the purchase of the land in Orillia.[266] It currently has about $18M already on the project.[267] All of this was done without an approved business case.

3.4.59 SEC submits this raises very serious concerns regarding Hydro One's planning process, especially for such a large project. Hydro One is requesting that the Board put the cart before the horse. A responsible utility would never ask its regulator and ratepayers for approval for the funds related to a project of such magnitude without providing an approved business case for the Board, and the customers, to review.

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[263] Tr.10, p.31-32

[264] JT3.01Q-7, Attachment 1

[265] Total forecast project costs allocated to distribution is $69.3M which represents 50.1% of the total cost of 138.4M total cost. Plan period costs allocated to distribution are 61.3M with a in-service date of 2020 leaving 8M having been spent before 2018. With 50.1% allocated to distribution, $8M already spent equals approx. $16M already spent in total for the project. See Exhibit B1-1-1, DSP Section 3.8, GP 18, p.12, 23 (updated); K10.1, p.9, 16;

[266] Exhibit B1-1-1, DSP Section 3.8, GP 18 (updated), p.6

[267] *Ibid*

3.4.60 The Board should deny approval of the cost consequences of this project, since there has been no approved business case. The Board should create a deferral account to capture the revenue requirement component of the project up to the proposed $69.3M capital cost[268], so as to allow the Board to determine at a later date whether the proposed project is prudent, after a public review of the approved business case. This would ensure that ratepayers are no worse off, and Hydro One has the ability to recover the revenue requirement of this project for the years, if any, it is in-service during the plan. This is a fair outcome for both ratepayers and Hydro One. The Board should also by way of condition, require the approved business case to be provided to the Board as soon as it becomes available. This is consistent with what Hydro One's counsel said the Board could do. [269]

3.4.61 SEC is also concerned that the in-service date is unrealistic. Mr. Irvine admitted during the hearing that the in-service date is at risk.[270] Hydro One's in-service date of Q3 2020 is based on construction beginning in September 2018.[271] Considering that the evidence is that Hydro One is waiting on the Board decision in this proceeding before even starting its business case, and then getting final approval, which based on its own schedule was supposed to occur in the summer of 2018, there is no way the in-service date will be met.[272]

3.4.62 In practical terms, at least one full construction season will be lost. The in-service date is not just at risk; it cannot be met.

3.4.63 ***Impact of New Vegetation Management Program.*** One of the benefits recognized by the new Optimal Cycle Protocol vegetation management plan is it will improve trouble calls and storm

[268] Adjusted for the later in-service date, and including only the component from in-service date to the end of 2022.

[269] Tr.10, p.27-28;

> MR. NETTLETON: Mr. Rubenstein, I mean, in all fairness, the answer to the response says "and will be provided once it is approved" The provision of the business case once it is approved could happen in many different ways. It could happen by way of conditions that the Board imposes. It could be through other, you know, other commitments that are made by Hydro One in this proceeding. [emphasis added]

[270] Tr.10, p.24-25

[271] Exhibit I-30-Staff-174(f); K10.1, p.27

[272] *Ibid*

repair capital work. Clear Path's final report explained the cost benefits from the increased vegetation management activity:

> Improvements in tree-related reliability can lead to significant savings in other lines of business. A reduction in the number of outages results in less straight-time and overtime payroll for call center staff, trouble men and line crews. Additionally, there are avoided costs associated with a reduced number of damaged facilities.[273]

3.4.64 Mr. Tankersley of Clear Path explained how damage to facilities can be avoided due to improving tree related reliability:

> MR. TANKERSLEY: Well, this is -- you can look at this in two areas: storm events and non-storm events. They both occur. In storm events you have many more occurrences of this happening. In storm events, particularly, as many as 50 percent of all interruptions may be attributed to vegetation. Through a more effective vegetation management program you are going to reduce that significantly, and this would be poles down, wires down, everything from the single customer up to major customers. It's the response time for the trouble, for the line maintenance and construction. I mean, it can impact a lot of different areas.[274]

3.4.65 Hydro One agreed with Mr. Tankersley's assessment.[275] Yet, it has not included any of those savings in its application. Its own Briefing Note to its Board of Directors states that one of the benefits of this new approach to vegetation management is that it will lead to a "[g]radual reduction in trouble calls stabilizing in 2023 and result in a $6 to $12M reduction".[276]

3.4.66 SEC submits the plan will provide cost savings benefits before 2023. Even based on Hydro One's own evidence, the utility expects annual reductions in outages before 2023 based on the implementation of this proposal.[277] Fewer vegetation management caused outages will by definition lead to less trouble calls.

3.4.67 Hydro One admits there will be savings during the test period, but does not want to include them in its forecasts. In its view, even though they are "seeing some early indicators of

[273] Exhibit Q-1-1, Attachment 2, p.13; K6.1, p.14

[274] Tr.6, p.104

[275] Tr.7, p.118

[276] Exhibit I-3-SEC-4, Attachment 4, p.2; K6.2, p.137

[277] *Ibid*

positive success, until….we see the actual results, we don't think it is prudent at this time to forecast a definitive dollar amount out four to five years."[278]

3.4.68 Since Hydro One has no problem forecasting costs out four to five years, there is no reason it should not forecast savings on the same basis. The Board should reduce Hydro One's trouble call capital budget to account for the expected savings as a result of the new vegetation management plan.

3.4.69 It is also not entirely clear why the trouble call budget would only stabilize in 2023 and not 2022. Based on Hydro One's own evidence, the reliability improvements in 2022 are going to be the same as 2023.[279] Since the trouble call savings should be entirely related to the frequency of outages, if those do not change between 2022 and 2023, the savings should not either.

3.4.70 SEC proposes that the Board reduce the trouble call budget by an average of $3.49M per year over the five years of the test period. This is based on a linear increase in savings each year until stabilizing in 2022 at $9M, the average of Hydro One's $6M to $12M forecast.

Vegetation Management Savings On Trouble Calls						
	2018	**2019**	**2020**	**2021**	**2022**	***2018-2020***
Trouble Call Savings ($M)	0.56	1.13	2.25	4.50	9.00	*3.49*

3.5 ***Business Case Approvals Process***

3.5.1 The Board should also require a third-party independent assessment of Hydro One's capital project/program approval processes. In the broader context there are concerns with Hydro One's internal approval process, as well as the fact that it does not even undertake a business case for its programs.[280] It only does a business case for individual projects that are more than $5M, an amount that is 5x its materiality threshold. Further, with the issues regarding the significant unit cost variances, there is a need to review how it manages changes in execution costs. This is consistent with the recommendations from Navigant/1QC regarding the need for

[278] Tr.p.120

[279] Exhibit I-3-SEC-4, Attachment 4, p.2; K6.2, p.137

[280] Tr.7, p.17;-18; Exhibit I-33-CCC-31

a formal change control process.[281]

3.5.2 All of this leads to a need to review Hydro One's internal approval and control processes to ensure the right information is provided to decision-makers to make the proper decisions at the proper intervals so as to ensure costs are controlled. This raises the question whether both, Hydro One's own management, and this Board, are getting the information they need to approve elements of Hydro One's work plan.

3.6 ***Summary***

3.6.1 SEC submits Hydro One's proposed capital spending in the test period is unreasonable and not adequately justified. SEC submits the Board should reduce the in-service additions, by an equivalent[282] of a reduction in capital expenditures of $558M over the test period. This proposed reduction represents approximately 15.6% of Hydro One's $3.57Bn proposed test period capital expenditure request.

SEC Proposed Capital Reduction $M)						
	2018	**2019**	**2020**	**2021**	**2022**	**2018-2022 Avg**
Pole Replacement Program	-8.6	-39.3	-46.6	-39.5	-27.5	***-161.5***
Substation Refubishment Program	-6	-6	-6	-6	-6	***-30.0***
Large Line Sustaining Initiatives	-7.4	-10.4	-10.3	-11.3	-11.2	***-50.6***
PCB Line Equipment Program	-2.4	-2.4	-2.5	-3.8	-3.9	***-15.0***
Trouble Call Savings	-0.56	-1.13	-2.25	-4.50	-9.00	***-17.4***
Smart Meter Replacement Program				-1.4	-79.9	***-81.3***
Remove ISOC Facility	-22.0	-36.3	-3.1			***-61.4***
Revised Project Contigency Level	-7.9	-7.9	-7.9	-7.9	-7.9	***-39.3***
Compensation Reduction	-20.3	-20.3	-20.3	-20.3	-20.3	***-101.5***
Total	***-$75.1***	***-$123.7***	***-$98.9***	***-$94.7***	***-$165.6***	***-558.0***

3.6.2 The proposed reductions will allow Hydro One to provide better value for money to customers by providing a reasonable overall increase in reliability, while at the same time listening to the views of its customers, which have unmistakably told the company they value rate impacts above all else.

[281] Exhibit B1-1-1, Section 1.6, Attachment 1, p.27

[282] Hydro One has provided the program level capex/in-service addition ratio in Undertaking JT.3.4.

4 COMPENSATION

4.1 *Overview*

4.1.1 Normally, the Board considers compensation costs primarily as they relate to the OM&A portion of an applicant's revenue requirement. This makes sense, since for most utilities, the vast majority of compensation costs are allocated to OM&A, and where utilities have big capital programs, they are likely to outsource the bulk of that work.

4.1.2 Hydro One's distribution business is different; for each year of the proposed test period more than half of the annual compensation is allocated to capital.[283] The biggest impact of the compensation costs over the test period is on the capital, not the OM&A part of the revenue requirement.

	2018	2019	2020	2021	2022
Capital Dx Compensation ($M)	342.4	347.8	333.2	324.6	327.7
OM&A Dx Compensation ($M)	295.4	294.7	298.1	291.6	294.3
Total Dx Compensation ($M)	637.8	642.5	631.3	616.2	622.0
% of Dx Compensation (Capital)	53.69%	54.13%	52.79%	52.68%	52.68%
% of Dx Compensation (OM&A)	46.31%	45.87%	47.21%	47.32%	47.32%
Source: JT 1.19, p.3, Table 2					

4.1.3 Just as capital is a significant part of compensation costs, on the flip side compensation costs are a significant part of the capital budget as well. Over the test period, 46.9% of the proposed capital expenditures are labour costs, with that amount being as high as 54.5% in 2018. A very significant portion of the capital plan, which is driving the need for a Custom IR application[284], is compensation costs.[285] Hydro One's inefficiency in its capital spending is undoubtedly due, at least in part, to its compensation problems.

[283] JT1.19, p.2, Table 2; K3.6, p.3, Tr.3, p.162

[284] Tr.1, p.158-159

[285] Tr.3, p.163

	2018	2019	2020	2021	2022	2018-2022
Total Capital Expenditures ($M)	628.1	736.4	699.4	710.9	796.4	3571.2
Capital Dx Compensation ($M)	342.4	347.8	333.2	324.6	327.7	1675.7
% of CapEx (Labour)	54.51%	47.23%	47.64%	45.67%	41.14%	46.92%
Source: 24-SEC-38, June 11 2018 update; JT 1.19, p.3, Table 2						

4.1.4 Compensation costs have been an on-going issue for Hydro One, arising as an important issue in almost every distribution and transmission application. The evidence in this proceeding is not only that these costs remain a problem, but compared to Hydro One's last distribution application, things are getting worse. Further, the problem may be worse than what was previously presented to the Board, with no improvement in sight.

4.1.5 It is time for the Board to send Hydro One a clear message, backed by immediate consequences, that Hydro One's customers will no longer be responsible for its above market compensation levels. Hydro One should no longer be in a position to argue that it is trying its best, and that it has strong unions, and all of the same excuses that have been trotted out in the past. Hydro One management should be responsible to deliver acceptable outcomes for its customers. In keeping with the analysis by the Supreme Court of Canada, the Board should, on behalf of the customers and in its role as market proxy, refuse to allow unreasonably high compensation levels to be included in rates. [286]

4.2 ***Compensation Benchmarking***

4.2.1 In Hydro One's last distribution proceeding, the Board made detailed findings and comments regarding the unreasonableness of the utility's compensation costs. The Board made very clear to Hydro One that it was not fair for ratepayers to have to pay a premium over the market median (P50).[287]

4.2.2 The evidence in this proceeding shows two things:

> ***(a)*** First, the gap between actual and market median pay has increased. Similar to its last distribution proceeding, Hydro One has not

[286] *Ontario (Energy Board) v. Ontario Power Generation Inc*. 2015 SCC 44 , para 120

[287] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.24

demonstrated the "market requires the level of compensation proposed in order to attract and retain the necessary employees" that would justify requiring such a premium.[288]

(b) Second, the studies are actually understating the real difference in compensation levels. The problem is worse than it previously appeared.

4.2.3 ***Deteriorating Performance.*** In the EB-2013-0416 decision, the Board found that based on the Mercer benchmarking study, the 10% premium Hydro One was paying was unreasonable and should not be borne by ratepayers. While the Board did not disallow the entire 10% premium, it did disallow half of it, recognizing that Hydro One had made consistent progress from previous years moving towards the median.[289]

4.2.4 Yet, it appears Hydro One is now moving backwards. Based on the new Mercer study filed in this proceeding, Hydro One is now at 12% above the median.[290]

4.2.5 In Hydro One's most recent transmission proceeding, the Board commented that it was "concerned that Hydro One's progress towards bringing its total compensation levels down to the market median has now reversed."[291] In making reductions to the proposed compensation costs, the Board stated that "for ratemaking purposes, compensation cost recovery should continue to trend towards the market median."[292]

4.2.6 In SEC's view, if the company cannot achieve these improvements, the issue is one of who should bear that excess cost as between the shareholders and the customers. SEC submits that the shareholders should bear that excess cost.

4.2.7 This is consistent with what the Board has said with respect to its role as the market proxy in a similar situation, in relation to OPG's attempt to pass above median compensation costs on to ratepayers:

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[288] *Ibid*

[289] *Ibid*, p.24-25

[290] Updated Compensation Study, Attachment (Mercer Study), filed April 20 2018, p.3; K3.6, p.14

[291] *Decision and Order* (EB-2016-0160 Hydro One Tx 2017-18), revised October 11, 2017, p.58

[292] *Ibid*, p.60

> 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 Board finds that it would not be reasonable to pass all of OPG's compensation costs on to ratepayers.[293]

4.2.8 What is most concerning is that the problem is likely to get *worse,* not better. Hydro One recently ratified a 2-year agreement with the PWU which includes compensation increases that are above what has been forecast in this application.[294]Further, Hydro One has adjusted its non-management compensation structure, which will see almost across the board compensation increases to managers and executives.[295] So, while these changes that have occurred since the filing of the application are not yet reflected in the proposed rates, it is a sign that Hydro One is not serious about taking control of their compensation levels.

4.2.9 ***Understated Differentials.*** This problem is exacerbated by the fact that the Board has been relying on studies by Mercer to assess the relationship between Hydro One compensation levels and the market median. In this proceeding, the Board has the benefit of a study by Willis Towers Watson ("WTW"), which uses a more thorough methodology and gets materially different results. In short, based on the WTW study, Hydro One is further above the market median than the Board previously thought.

4.2.10 The Mercer study that the Board has used to track Hydro One's progress (or lack thereof) compared to the market median, only compared Hydro One to other large energy and utility companies. It may make sense to do so for positions that are unique to the utility business, but it does not for other positions. A significant portion of Hydro One's positions in each of its major categories (PWU, Society, Non-Represented) are jobs that are not unique to the industry[296], and therefore should be compared to the broader comparator group from which those personnel would be recruited.

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[293] *Decision with Reasons* (OPG - EB-2013-0321), November 20 2014, p.80

[294] Tr.11, p.129; See also Hydro One Networks Inc.'s Distribution 2018-2022 Rate Application – Memorandum of Agreement with PWU and Variance Analysis, filed on July 11 2018

[295] Updated Compensation Study, Attachment (WTW), filed April 20 2018, p.7; Exhibit I, Tab 40, Schedule SEC-102(e)

[296] Tr.4, p.178-179

4.2.11 Mr. Resch[297] from Willis Towers Watson testified that this approach is preferred.[298] If one compares support positions to those only in like utility companies, Mr. Resch's view is that those support positions would be closer to the median market position than is actually the case. This is because "market data is higher amongst utility companies in Canada, [compared to] general industrial". You do not want to compare all positions' compensation to those at utility companies, because if you did you would be "inflating market levels by comparing non-utility roles to other utility organizations."[299] The approach Mr. Resch recommended is what is known as the segmented approach.[300]

4.2.12 An example of this is comparing the Mercer study results for the PWU as compared to the study that Willis Towers Watson completed for Hydro One regarding PWU compensation in 2017.[301] The Mercer study, which compares PWU positions to only those in other energy and utilities companies, finds that on total cash basis, the PWU is 1% above the median.[302] Willis Towers Watson shows that for positions that are in operations, and thus appropriately compared to other utility companies, Hydro One is actually below the median on a total cash compensation basis. But, when comparing non-utility-specific positions (what it calls core services) to the broader general market, WTW found that Hydro One pays 64% above the market median.[303]

4.2.13 Overall, Willis Towers Watson's evidence is that PWU is paid 7% above the market median

[297] Mr. Resch testified as an expert witness in the EB-2016-0160 regarding his reports that where filed as well in this proceeding (Exhibit C1-2-1, Attachment 1 and 2). His testimony was agreed to be by the parties to be incorporated into this proceeding. See Hydro One Letter Re: Response to Procedural Order No.3, January 18 2018, p.3

[298] Tr.9, 127 (EB-2016-0160):

> 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. ….

[299] Tr.9, p.137-138 (EB-2016-0160)

[300] Tr.9, p.138 (EB-2016-0160)

[301] Exhibit 1-3-SEC-3, Attachment 1

[302] Updated Compensation Study, Attachment (Mercer Study), filed April 20 2018, p.17; K3.6, p.28

[303] Exhibit 1-3-SEC-3, Attachment 1, p.7; K3.6, p.49

on a total cash basis as compared to the 1% in the Mercer study.[304] This is a significant difference[305].

4.2.14 The situation in the case of total compensation is even worse. The PWU in the Mercer study is only 1% above the median on a cash basis, but on a total compensation basis it is 12% above the median.[306] We do not have similar data from WTW on a total compensation basis using the segmented approach, but clearly it would have been significantly higher than the 12%. The evidence before the Board thus suggests that the true benchmark of Hydro One's total compensation is well above what is shown in the Mercer study.

4.2.15 Hydro One must believe that this approach provides a much more accurate view of how it compares to the market than what Mercer has stated. Hydro One has commissioned Willis Towers Watson to provide compensation benchmarking information using the segmented approach for non-management[307] and the PWU[308], and is expected to ask them to complete an additional study with respect to the Society in the future.[309]

4.2.16 There are also some other aspects of the Mercer study that concern SEC.

4.2.17 Mercer only benchmarked 59% of Hydro One's employees – meaning 41% are not part of the study.[310] This is a very significant proportion of Hydro One's employees that are not part of

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[304] *Ibid*

[305] If this 7% is applied to all PWU cash compensation, the average annual excess compensation for those employees is about $16M: See Exhibit C, Tab 2, Schedule 1, Attach 6, p. 5 and 6.

[306] Updated Compensation Study, Attachment (Mercer Study), filed April 20 2018, p.17; K3.6, p.28

[307] (Exhibit C1-2-1, Attachment 1 and 2). ; Updated Compensation Study, Attachment (WTW), filed April 20 2018

[308] Exhibit 1-3-SEC-3, Attachment 1, p.7; K3.6, p.49

[309] Exhibit 1-3-SEC-3, Attachment 1, p.2:

> Hydro One's comparator groups have been differentiated to reflect the segmented labour markets for talent i.e. Operations and Core Services roles, and will be applied consistently for the following employee groups to ensure a consistent end-to-end approach to understanding market position holistically:
>
> - Executive
> - Management Group
> - PWU represented roles
> - Society represented roles (benchmarking has yet to commence) [emphasis added]

[310] Tr.3, p.170

the benchmarking analysis. Mr. Morris on behalf of Mercer did not appear to be troubled by this, stating that this level of participation was similar to other such studies they have conducted.[311] Yet, Willis Towers Watson was able to do significantly better. It was able to benchmark over 90% of Hydro One's PWU employees. [312]

4.2.18 Considering the gap between the results of the two studies (at least with respect to the PWU), it may be that some part of the reason for the difference is not just the segmentation approach, but also the number of benchmarked positions.

4.2.19 The Mercer study also leaves out a significant component of compensation – overtime.[313] These amounts can be significant, especially when Hydro One is engaged in storm restoration efforts and undertaking other time-sensitive work. Overtime for these purposes can be expected. More troubling is that, as Hydro One's own internal audit group has reported, overtime is being used to ensure planned in-service dates are met.[314] No wonder that Hydro One is spending more and delivering less in its capital plan.

4.2.20 To put the magnitude of overtime costs in perspective, in 2017, the year the Mercer study was undertaken, over 7% of total hours worked by Hydro One employees were overtime hours.[315] More significantly, 83.5% of overtime hours are paid at double time.[316] Overtime is a very significant part of Hydro One's compensation costs[317], and its availability is part of the overall package it provides as an employer. Hydro One must include overtime costs in its next compensation benchmarking study.

4.2.21 In fact, the total value of overtime is only going to increase. Based on the approved

[311] Tr.3, p.170

[312] Exhibit 1-3-SEC-3, Attachment 1, p.4; K3.6, p.46

[313] Tr.3, p.96

[314] JT3.2, Attachment 4, Attachment A, p.9; K3.5, p.27

[315] JT2.4. 7.02% = 2017 Total Overtime Hours(1,002,514)/ [2017 Regular hours (13,271,988) + 2017 Total Overtime Hours (1,002,514)]

[316] JT 2.4. 83.5% = 2017 Overtime Hours at 2x (837086)/ 2017 Total Overtime Hours (1,002,514)

[317] Approximately $80M for PWU in 2017, of which about $33M is allocated to distribution, and increasing in each year of the plan term: Exhibit C1, Tab 2, Schedule 1, Attach 6, p. 5 and 6.

Memorandum of Agreement between Hydro One and the PWU, Hydro One will no longer pay the first two hours of overtime at 1.5 times the usual rate.[318] All overtime will now be paid at 2 times the employee's usual rate.[319]

4.3 ***Staffing***

4.3.1 Hydro One's staffing numbers also continue to be a concern. Between 2014 and 2015, Hydro One reduced its headcount numbers by over 230 FTEs, in part in response to concerns expressed by this Board.[320] The numbers then began to increase and, by 2018, they are forecast to be at 8581, which is also an increase over the 2017 FTE numbers.[321]

4.3.2 Hydro One has said the FTE numbers are declining between 2017 and 2022. This is technically correct, as in the 2022 forecast FTEs will be lower than the 2017 FTEs.[322] But, the trajectory is not reductions year over year from 2017.[323] The reduction only begins in 2019, which will then see year over year absolute reductions in FTEs through to 2022.[324] Thus ratepayers will not see the benefit of those reductions until the next application, for 2023 rates.

4.3.3 Hydro One has in effect placed its FTE 'peak' in the 2018 test year, with almost half the subsequent savings (i.e. the OM&A portion) only going to Hydro One during the test period. That is not appropriate and is another reason to reduce Hydro One's compensation costs.

4.3.4 Hydro One has admitted that their planned FTE numbers do not represent 'optimal' staffing levels.[325] Yet in their view, a staffing benchmarking study or similar analysis regarding staffing numbers is not a priority for them.

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[318] Memorandum of Agreement, filed July 11 2018, Attachment 1, section22.3, p.12.

[319] *Ibid.* Based on the forecasts of overtime in Exibit C1, Tab 2, Schedule1, Attach 6, the PWU overtime for the plan term, currently forecast at $172.2M, would increase to $176.9M due to this adjustment in the collective agreement (based on 83.5% of hours at 2 times, and 16.5% of hours at 1.5 times, which is a weighted average of 1.947 times, compared to 100% of hours at 2 times).

[320] JT 2.05, Attachment 1, p.1; K3.6, p.61

[321] *Ibid*

[322] C1-2-1, p.9, Table 1; K3.6, p.60); JT 2.05, K3.6, p.61

[323] Exhibit I-40-Schedule Staff 205

[324] C1-2-1, p.9, Table 1 (K3.6, p.60)

[325] Tr.4, p.898

4.3.5 While a staffing study may not be a priority for management, in our view it should be a priority for this Board. It is something that a utility the size of Hydro One should present to the Board in time for its next application. An analysis like this would not only benefit the Board, but more importantly, Hydro One in ensuring that it eventually reaches optimal staffing levels.

4.3.6 The requirement for a staffing study is something the Board has ordered before. It has required OPG to undertake and file staffing studies for its nuclear operations in its payment applications for some time now.[326] It should do so for Hydro One as well.

4.4 ***Pensions & Benefits***

4.4.1 ***Benchmarking.*** The Mercer study reveals that the biggest cause of Hydro One's above-market compensation costs is Hydro One's very generous pension and benefits plan with its unionized workers. [327] Over the test period, Hydro One forecasts spending $460M in pension and OPEB costs allocated to distribution, about 14.6% of total distribution compensation.[328]

4.4.2 This issue includes not just the level of benefits but more importantly who bears the cost of funding them as between Hydro One and the employees. The funding contribution ratio between Hydro One and its employees has been an issue the Board has commented on critically in the past, since it is significantly above the normal 50/50 ratio.[329] The Board commented in the EB-2013-0416 decision that it expected further progress to be made after 2019:

> Hydro One has reduced the employer pension contribution level such that the employer/employee ratio for 2015 is planned to be 72/28. Hydro One has indicated that it plans to move to a 65/35 ratio by 2019. This progress must continue, and the OEB encourages Hydro One to continue to move toward a 50/50 ratio, the generally recognized norm in public sector defined benefit pension plans.[330]

[326] *Decision and Order* (EB-2016-0152 - OPG 2017-2021), December 28 2017, p.78

[327] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.25

[328] Exhibit C1, Tab 2, Schedule 1, Attachment 6, p.7

[329] *Ibid*

[330] *Ibid*

4.4.3 Yet, Hydro One's agreement with the PWU contains no further progress towards an equitable contribution ratio. Hydro One appears to have bargained higher than forecasted base wage increases, and increased overtime rates, in exchange for nothing with respect to pension and benefits. This is an unreasonable result for ratepayers.

4.4.4 ***Pension Holiday***. As part of its compensation costs, Hydro One is seeking to recover $37M in pension costs in 2018 (17M in OM&A and $20M).[331] It will also seek to recover similar amounts in capital from 2019 to 2022 through the C-factor. The evidence is that Hydro One is not actually required to make any further contributions to its pension plan at this time as it is in a significant surplus position ($433.7M).[332]

4.4.5 Hydro One's rationale for still paying into the pension plan during the test period is that even though it can legally take a funding holiday under pension rules, if fund performance and economic conditions change then the fund may change to a deficit position and possibly special payments may be required.[333]

4.4.6 SEC does not disagree that there is a *risk* that there could be substantial external factors which push the fund into a deficit position. The question is how big that risk and how much should it matter. Hydro One has a variance account to capture the variance between forecast pension costs built into rates and actuals, so it is entirely protected from changes in external factors. Today's ratepayers should not be asked to pay into the pension plan when Hydro One is not required to provide any, let alone, the full amount at this time. To put the surplus amount in perspective, the entire pension contributions forecast for both distribution and transmission for 2018 to 2022 is $344M, compared to the surplus at the end of 2017 of $433.7M.[334]

4.4.7 Mr. Chhelaavda testified that there is a legal constraint on Hydro One's ability to take a pension holiday under its collective agreement with its unions that requires that employer

[331] Exhibit C1, Tab 2, Schedule 2, Table 1

[332] Exhibit C1, Tab 2, Schedule 2, Attach 1, p.4, 11.

[333] Tr.4, p.78-79

[334] Exhibit C1-2-1, Attachment 6, p.7; Exhibit C1, Tab 2, Schedule 2, Attach 1, p.4

pension contributions cannot be less than the employee contributions.[335] SEC submits that since Hydro One cannot take a full funding holiday, it should be required to lower its contributions to the plan to equal that of its employees. This is possible since Hydro One contribution ratio is significantly higher than 50:50.

4.4.8 SEC has not provided an exact amount for this proposed reduction to the 2018 OM&A and 2018-2022 capital expenditures since that specific amount of Hydro One's pension contribution over the employees contribution is not on the record at this time. This additional amount should be added to the proposed OM&A and capital reductions.

4.5 ***Reductions***

4.5.1 Even without adjustments to the benchmarking, to include overtime and a broader range of positions (segmented approach), the compensation levels at Hydro One are known to be materially above market. Hydro One has been warned by this Board in the past that it has to deal with that issue, but the problem is getting worse, not better.

4.5.2 Based on the analysis Mercer conducted, and then verified in Undertaking J3.11, the difference between Hydro One's 2017 actual compensation levels and the benchmark level is $70.9M on a company wide basis.[336] Using the 2018 labour allocation methodology provided by Black & Vetch, this would result in a reduction of 2018 distribution capital expenditures of $20.27M, and a reduction of $17.48M in OM&A.[337] For 2019 to 2022, the Board should make similar annual reductions in capital expenditures of $20.27M per year. This is because, unlike OM&A, which is indexed directly from the 2018 test year, capital is being recovered in its entirety through the C-factor.

4.5.3 An added benefit of this approach is it includes the impact of the higher than average pension contribution ratio, as that is included in the Mercer study.[338]

[335] Tr.4, p.78

[336] J3.11; Exhibit I-40-SEC-83(a)

[337] Exhibit I-40-SEC-83(a) (updated June 7 2018)

[338] Tr.3, p.36

4.5.4 SEC notes that moving rate-recoverable compensation levels down to the Mercer benchmark does not achieve real market levels, given the WTW results. However, it would be a significant step towards dealing with the issues of peak compensation in 2018, escalation of FTEs, high reliance on overtime, and low employee contributions to their own benefits. It is an incremental step beyond what the Board has previously ordered in Hydro One cases, and would allow further review, with better data, at the next rebasing.

4.5.5 SEC agrees with past statements of the Board that the ultimate goal should be Hydro One total personnel costs that are indicative of benchmark costs. The proposed reduction should be the minimum reduction the Board should order to move closer to that goal.

5 OM&A

5.1 *Overview*

5.1.1 Hydro One is seeking approval of $576.7M in OM&A for its 2018 test year.[339] It then proposes to increase the approved OM&A amount annually beginning in 2017 by the Board's annual inflation factor, net of the approved productivity and stretch factors.[340]

5.1.2 SEC recognizes that the proposed 2018 amount represents a reduction from the amount approved and built into rates for 2017. [341] But it is, however, an above inflation increase of 2.1% over the 2017 actuals[342], and all of Hydro One costs must be assessed against the backdrop of a utility that is consistently incurring more than its benchmark level of costs to deliver services to its customers.

5.1.3 SEC will therefore propose reductions to OM&A, in addition to those reductions that would flow out of the compensation discussion, above.

5.2 *Incorrect Forecasts*

5.2.1 SEC submits that Hydro One has over-forecasted its OM&A, and that it will spend less in 2018 than the amount for which it is seeking the Board's approval to include in rates.

5.2.2 This is similar to what occurred in 2017. When Hydro One filed this application in late March 2017, it forecasted a 2017 OM&A of $580.5M.[343]344 In its June 2017 update it revised that forecast down to $572.8M.[345] But even that revised forecast was not accurate; the actual year-end 2017 OM&A was $558.7M.[346]

5.2.3 The evidence is that 2018 is likely to see actual OM&A at a level well below the 2017 actuals.

[339] Tr.2, p.91; J1.10

[340] Exhibit A-3-2, p.6

[341] Exhibit I-38-SEC-70(a); K2.2, p.20

[342] *Ibid*

[343] Exhibit C1-1-1, p.2, Table 1 (Original Filed)

[344] Exhibit C1-1-1, p.2, Table 1 (Original Filed)

[345] Exhibit I-38-SEC-70(a); K2.2, p.20

[346] Exhibit I-38-SEC-70(a); K2.2, p.20

During Hydro One's Q1 earnings call, Paul Dobson, the Chief Financial Officer, stated that quarter-over-quarter (i.e. 2018 Q1 over 2017 Q1) "distribution OM&A was down 4.1%, reflecting lower corporate support costs."[347] Mr. Lopez, however, testified that the result is "entirely timing" and that the annual 2018 forecast has not changed.

5.2.4 SEC submits this is not credible. Hydro One would not be boasting to market analysts that its Q1 distribution OM&A was down 4.1% quarter-over-quarter if that number was not sustainable throughout the year. Likely the opposite is true. Prudent management would have qualified the results with Mr. Lopez's comments so as not to unnecessarily raise expectations of the market, unless management was confident the reduction could be sustained.

5.2.5 SEC submits that the Board can reasonably expect 2018 OM&A to be at least 4.1% below 2017 OM&A, based on management's public statements, i.e. about $536M. That should be the maximum amount included in rates for the 2018 rebasing year. We note that, since the management statement did not include any adjustment for above market compensation, the compensation adjustment SEC has proposed earlier should reduce that OM&A budget further.

5.3 ***Vegetation Management***

5.3.1 Vegetation Management is Hydro One's single largest OM&A program, with a forecast 2018 cost of $149.6M.[348] These costs have been a subject of considerable criticism from the Board in past proceedings.

5.3.2 In Hydro One's last distribution application, the Board disallowed $39M in vegetation management costs, after benchmarking evidence filed demonstrated that Hydro One has the highest vegetation management cost per customer relative to its peers.[349] It further directed Hydro One to undertake a trend analysis and "encourage[d] Hydro One to explore best practices in vegetation management with other distributors and transmitters."[350]

[347] Exhibit I-38-SEC-70(a); K2.2, p.20

[348] Tr.7, p.105; C1-1-2, p.29, Table 5

[349] *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.26

[350] *Ibid*, p.27

5.3.3 After seeing the results of the trend analysis work undertaken by CN Utility Consulting, Hydro One retained Clear Path to work with it to develop a new vegetation management strategy.[351] It worked with Clear Path throughout 2017, and unveiled as an update to its application in the fall of that year its new vegetation management strategy – the Optimal Cycle Protocol. [352]

5.3.4 The new Optimal Cycle Protocol strategy is a significant change, and involves moving to a three-year tree trimming cycle that focuses on defects, instead of completely clearing all vegetation in a corridor, as with its previous approach.[353] Clear Path's assessment, after spending time in the field with Hydro One and reviewing various materials available, was that "approximately 30% to 50% of the work performed had little or no material impact on the key objectives" of the program.[354]

5.3.5 Clear Path's stark conclusion was that Hydro One's approach was "considered 'gold plating' relative to typical industry practices for distribution facilities".[355] In essence, Clear Path was saying that Hydro One has wasted hundreds of millions of dollars in ratepayer funds over the years. Mr. Tankersley said it was a fair characterization that 30 to 50% of Hydro One's previous vegetation management work "essentially provided little to no benefit".[356] To put that in perspective, based on Hydro One's 2014-2016 vegetation management spending (the three years preceding Clear Path's analysis), that would be anywhere between $123.6M to $206M.[357] This is a startling amount of imprudent spending.

5.3.6 This new Optimal Cycle Protocol approach will allow Hydro One to "reasonably expect a 20% to 40% (or better) reliability improvement moving to a shortened maintenance cycle, updating the patrol standard to match clearance requirements to cycle interval and

[351] Q-1-1, p.12; K6.2, p.139

[352] *Ibid*; Tr.7, p.106-107

[353] Tr.5, p.164; Q-1-1, p.13; K6.2, p.140

[354] Exhibit I-38-CCC-44, Attachment, p.10; K6.2, p.144

[355] *Ibid*

[356] Tr.5, p.166

[357] 2014-2016 vegetation management actuals of 411.9M (See C1-1-1, p.29, Table 5; K6.2,p.134)

implementing a more rigorous approach to hazard tree mitigation."[358] This is in addition to the cost savings discussed in section 4.6.3 related to reduced trouble calls and storm damage.[359]

5.3.7 Yet, even though Hydro One dramatically changed its vegetation management strategy in the midst of the application, that change had no effect on the proposed 2018 program budget.[360]

5.3.8 SEC submits a complete change in the approach must have *some* impact on the budget. Clear Path's final report forecast that this new 3-year cycle based on its proposed approach should cost about $108.4M.[361] While this amount does not include other activities such as customer demand work, enhanced hazard tree work, among other areas, it does reflect an amount that is $41.2M below Hydro One's forecast.[362] Even with those other areas included, SEC submits the actual cost should be materially below the requested $149.6M.

5.3.9 A reduction in annual spending is also consistent with what happened in 2017. Hydro One introduced the new Optimal Cycle Protocol in the fall of 2017, and Hydro One's actual tree vegetation management costs for all of 2017 were 6.5% below its own internal budgeted amount.[363]

5.3.10 SEC submits the Board should make a similar (adjusted for a full year) reduction in vegetation management costs for the 2018 test year, i.e. 13%, or about $18.6M. This would still leave Hydro One $22.6M higher than the Clear Path forecast, more than enough to cover the additional areas.

5.3.11 SEC notes that this would not be incremental to the reduction set out in paragraph 5.2.5 above, since the reduction in costs from Q1 2017 to Q1 2018 would include reductions in vegetation

[358] Q1-1-1, Attachment 2, p.13

[359] *Ibid*

[360] Q-1-1, p.12; K6.2, p.139; Tr.7, p.142

[361] Q1-1-1, Attachment 2, p.15, Table 8; Tr.5, p.171-172

[362] Q1-1-1, Attachment 2, p.15

[363] 2017 HONI approved vegetation management budget $138.5M (Exhibit I-3-SEC-4, Attachment 4, p.3; K6.2, p.138) 2017 Actual Vegetation Management costs 129.4 (Tr.7, p.108).

management costs. It does, however, provide a bottom-up rationale for a significant component ($18.6M of the $36.1M total) of the 4.1% proposed reduction.

5.4 *Information Technology*

5.4.1 Information Technology ("IT") is a common cost that is allocated between Hydro One's distribution and transmission businesses. Hydro One is proposing to spend $80.4M in IT OM&A for distribution in 2018.[364] This is a significant amount, which represents 14% of its proposed OM&A expense. [365] In addition, Hydro One is seeking to spend an average of $41.9M ($209.7M) a year in IT capital during the test period.[366]

5.4.2 In support of its application, Hydro One filed a benchmarking assessment undertaken by Gartner Consulting regarding its Information Technology capital and OM&A spending plans. [367] The conclusion from the study is that Hydro One, on a company-wide basis, spent a similar amount on IT compared to its peer companies, albeit with differences regarding how it was spent.[368]

5.4.3 Hydro One's takeaway after it reviewed the study was that it "compare[d] favorably with our industry peers, in terms of our overall spend."[369] This was primarily demonstrated not just by the difference between the total spending ($200.1M peer average versus $194.9M Hydro One)[370], but also as represented by spending as a percentage of total revenue (3.1% peer average versus 3% for Hydro One[371]).[372]

5.4.4 The problem with relying on the benchmarking study is that it was undertaken in 2016, based on 2015 data.[373] The evidence is that 2015 is not reflective of spending either in the 2018 test

[364] Exhibit C1-1-9, p.2, Table 2; K10.1, p.39

[365] $80.4M (Exhibit C1-1-9, p.2, Table 2) / $575.2M (J1.10)

[366] Exhibit B1-1-1, DSP Section 3.2, p.10; K10.1, p.38

[367] Exhibit B1-1-1, DSP Section 1.6, Attachment 3

[368] *Ibid*, p.10; K10.1, p.29

[369] Tr.10, p.33

[370] *Ibid*, p.10; K10.1, p.29

[371] *Ibid*

[372] Tr.10, p.34

[373] Tr.10, p.33

year, or for any year since 2015.

Hydro One IT Spending (Dx + Tx)				
	2015	2016	2017	2018
Capital ($M)	51.50	94.30	77.00	71.60
OM&A ($M)	142.5	143.8	145.7	137.9
Total ($M)	194.00	238.10	222.70	209.50
Total Revenue ($M)	6,529	6,502	5,990	
% IT Spend/Revenue	3.0%	3.7%	3.7%	
Source: J10.4; Exhibit C1-1-9, p.2, Table 1; JT1.8, Attach 1, p.3				

5.4.5 As shown in the above table, Hydro One's capital spending on IT dramatically increases after 2015, both in total spending and as a percentage of total revenue. While the proposed 2018 spending is less than the 2017 spending, based on a reasonable forecast of total revenue, it is still likely to be well above the 3.1% peer average benchmark.

5.4.6 In fairness to Hydro One, we do not know what the peer average would be in 2018, which due to cyber security concerns may have increased as a percentage of total revenue. Complicating matters is that the total revenue that is used in the study includes revenue Hydro One receives for the commodity, which is just a pass-through.[374]

5.4.7 SEC questions using total revenue as a proper denominator for measuring IT spending. It is not clear that in the utility industry total revenue is a driver of IT costs (either with pass-through costs, or without) as opposed to, for example, number of FTEs. Using that metric, Hydro One is approximately 7% *above* the benchmark on IT spending per employee.[375] In OPG's last payment amounts application, as a result of a previous Board order, they undertook a benchmarking study of corporate support functions.[376] In that study, undertaken by a different consultant (Hackett Group), IT costs were measured on a 'per end-user' metric,

[374] The definition of revenue includes fuel (See Exhibit B1-1-1, DSP Section 1.6, Attachment 3, p.16; K10.1,p.36). In addition, the 3% 2015 number only works based on using total revenues, not revenue net of purchased power (See https://www.hydroone.com/investorrelations/Reports/Hydro%20One%20Ltd%204Q15%20Earnings%20Release.pdf)

[375] Hydro One 2015 IT spending per employee of 35,340 / Peer average 2015 IT spending per employee $32,911 (Exhibit B1-1-1, DSP Section 3.2, p.10; K10.1, p.38)

[376] *Decision and Order* (EB-2016-0152 - OPG 2017-2021), December 28 2017, p.69

whereas other non-IT metrics were measured as a percentage of revenue.[377]

5.4.8 Due to this uncertainty, it is hard to propose with any specificity what reductions would be warranted. If it makes no reductions to IT OM&A, at the very least the Board should require Hydro One to conduct an update of the IT benchmarking study that includes analysis of what the drivers are of IT spending, so a more detailed analysis can be done at Hydro One's next rebasing hearing.

5.5 ***Summary***

5.5.1 SEC submits the Board should reduce Hydro One's proposed 2018 OM&A expenditures by $36.1M.

SEC Proposed OM&A Reduction $M)	**2018**
Compensation	-17.5
Vegetation Management	-18.6
Total	***-$36.1***

[377] *Ibid*

6 COST ALLOCATION & RATE DESIGN

6.1 *Introduction*

6.1.1 SEC will limit its Final Argument on these issues to one area, the integration of the Acquired utilities from Woodstock, Norfolk, and Haldimand. Although this part of our Final Argument is under the heading 'Cost Allocation and Rate Design', it includes all of our submissions relating to the Acquireds, including Issue #14, Issue #56, and others.

6.1.2 What SEC will conclude from the following analysis is that Hydro One has not proposed a viable approach to bringing the Acquireds into their rate structure. Essentially, Hydro One has failed to follow the Board's guidance from prior cases, and as a result has proposed an inappropriate harmonization proposal.

6.1.3 The Hydro One proposal suffers from three fundamental problems:

(a) ***Structurally Flawed.*** It is conceptually and methodologically unsound. In essence, it is a combination of short-term fixes that do no more than fudge the numbers.

(b) ***Lack of Equity Between Customers***. The proposal seeks to apply different cost allocation and rate design principles to different groups of customers, and thus is at its root, unfair.

(c) ***Unsustainable.*** Hydro One designed this approach to apply to future acquisitions, but it can be shown that it cannot be so applied while still being consistent with the "no harm" test and long-accepted cost allocation principles.

6.1.4 SEC will therefore submit that the Board should respond to the Hydro One proposal for the Acquireds as follows:

(a) Deny approval to establish the six proposed new rate classes.

(b) Direct Hydro One to commission an external analysis of their acquisition and harmonization strategies, with a view to identifying solutions that are conceptually sound, fair to all customers, both existing and new, and reasonably likely to be applicable to future acquired customers.

(c) Until Hydro One has presented that study to the Board, and a new, reasonable harmonization approach has been approved, continue the current decoupling of the rates of the Acquired from costs by escalating their rates annually, starting in 2021, by the weighted average rate increase applicable to all other Hydro One customers as approved by this Board.

6.2 ***Background***

6.2.1 Hydro One is by far the most acquisitive distribution company in Ontario, having acquired more than ninety other distributors since market opening.[378] Hydro One regularly offers large premiums over book value, and a cash price, thus providing ready funds for other municipal priorities.

6.2.2 It is also able, because of its operations around the province, to offer additional perks that are the real reasons that some municipalities are willing to sell. In Orillia, for example, the biggest reason for the City's interest in selling is the Integrated System Operations Centre proposed by Hydro One.

6.2.3 Given this lengthy history, Hydro One has had to integrate numerous new customers into its operations, and harmonize their rates. It does not have a good track record in that regard.

6.2.4 ***EB-2005-0378 – 2006 Rates***. In 1999 and 2000 Hydro One acquired scores of small distributors during the market opening frenzy. In 2005, in a case a little reminiscent of the current proceeding, Hydro One proposed to the Board that all of those acquired customers, 136,000 of them, be lumped together and given new rates through a complex set of steps. They would not be harmonized with existing customers, but they would be partially harmonized with each other.

[378] 88 harmonized in EB-2007-0681, and three acquired since then. Alectra, Veridian, and Entegrus, those next in order, are all at 10 or fewer.

6.2.5 The Board rejected the Hydro One proposal as being premature. Harmonization, said the Board, should be done on the basis of a proper cost allocation process, and until Hydro One had done that, the rates should not be harmonized.

6.2.6 During the course of the analysis, the Board made an interesting observation:

> Obviously rates for all Acquired LDC customers will increase as a result of the combination of the cost allocation process and harmonization with Hydro One's legacy customers. [379]

6.2.7 Simply put, the Board recognized that, when a high cost utility like Hydro One acquires new customers, those new customers will ultimately have rate increases. Higher costs mean higher rates. It is inevitable, driven by the math.

6.2.8 ***EB-2007-0681 – 2008 Rates.*** As a result of the failed attempt to harmonize for 2006, Hydro One still had 280 rate classes when it came to the Board for 2008 rates.[380] Against that background, Hydro One sought to harmonize both legacy and acquired customers into twelve customer classes.

6.2.9 The rate increases for acquired customers were shocking. The average general service demand billed customer would have a rate increase, when the harmonization was phased in fully, of 515%.[381] For the general service urban density demand billed, a new class created in response to stakeholder concerns[382], the average increase was 289%. The range varied, with some customers from low cost utilities having increases in excess of 1000%.[383]

6.2.10 The Board, although expressly unhappy with the evidence that it had to work with, and unhappy with the large increases it was ordering for the acquired customers, ultimately accepted the Hydro One proposal. As the Board put it: "the process needs to move

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[379] *Decision with Reasons* (EB-2005-0020/0378 - Hydro One Dx 2006), April 12 2006, p.42

[380] *Decision with Reasons* (EB-2007-0681 - Hydro One Dx 2008), December 18 2008, p.21

[381] For the source of all of these numbers, see EB-2013-0187, SEC Final Argument, Appendix B.

[382] This is the change in rate classes that Mr. Andre did not remember during oral evidence. See Tr.10, p.188

[383] In residential, the average R1 increase was 240%, and for UR it was 95%.

forward".[384]

6.2.11 There is no way to sugar coat it. The EB-2007-0681 Decision is not the Board's finest hour. Faced with evidence that 136,000 customers would face massive rate increases, year after year for four years, the Board allowed it to happen. Only the Board was in a position to protect those customers, and it failed to do so. Many of those customers still have rates that are double, or higher, what they would have been absent those acquisitions.

6.2.12 That having been said, the context of that decision, and the EB-2005-0378 decision, is important. At that time, the "no harm" test was fairly new, and the Board had not yet grappled with the complications of rate differentials as being an aspect of harm to customers. Also at that time, the Board had just completed its first cost allocation consultation – largely driven by Hydro One – and had a new and untested cost allocation model. The entire industry believed that only Hydro One really had a firm grasp on cost allocation, so everyone followed their lead.

6.2.13 And, of course, these rate harmonization decisions were after the fact. The Board was dealing with acquisitions that were fait accompli. No-one was going to make these customers independent of Hydro One (and its high costs) again. They were stuck as part of the Hydro One system, and the Board had to make the best of a bad situation. As the Board noted, rates for the Acquireds were going to go up. The only question was how, and how much.

6.2.14 ***EB-2013-0187 – Norfolk MAADs***. In 2013 Hydro One started its new series of acquisitions with an agreement to purchase Norfolk Power, centred in Simcoe, Ontario. The proposed structure of the purchase was essentially identical to the 88 distributors that were the subject of EB-2007-0681: a five year rate freeze with a 1% reduction, followed by an "all bets are off and we do not know what will happen" period after.

6.2.15 The context, however, had changed. The Board already had experience with regulating Hydro One's rates, and with the cost control challenges it was facing. The Board also had additional years of experience with both the "no harm" test and the cost allocation model, and it could

[384] *Ibid*, p. 24

view, with hindsight, what had happened to the customers of the previous 88 acquired distributors.

6.2.16 Hydro One continued to argue, however, that as long as the underlying cost structures overall will go down (i.e. as long as there are net cost savings, no matter who benefits from them), the financial aspects of the no harm test are met. Customer groups argued, on the other side, that if the rates for the customers of an acquired utility go up as a result of the acquisition, those customers are harmed, and the test is not met.

6.2.17 The Board in its decision was unwilling to refuse approval to Hydro One, particularly in the policy context in which distributor consolidation was being actively supported by the government, the Board, and the industry (and, in fact, by the customer groups). On the other hand, the Board recognized that raising rates as a result of an acquisition is not consistent with the no harm test. The Board said:

> The Board determined that to assess the ultimate impact on NPDI customers, it would need to examine the cost structures that would result from the transfer of NPDI's distribution system to HONI. The Board considers that the relationship between costs and rates is of prime importance in understanding the impact of the proposed acquisition. **Clearly increased or decreased costs would be expected to have a corresponding effect on future rates.**[385]
>
> …
>
> Concerning the setting of future rates, it is the Board's expectation that **at the time of rate rebasing HONI will propose rate classes for NPDI customers that reflect costs to serve the NPDI service area, as impacted by the productivity gains due to the consolidation.** [emphasis added] [386]

6.2.18 The effect of this decision was to signal to Hydro One that it was not enough for overall costs to go down as a result of an acquisition. The acquired customers would have to share in the benefit of that cost reduction for the no harm test to be met.

6.2.19 In this proceeding, Hydro One witnesses characterize this as a new rule for harmonization of acquired customers. The entire Hydro One proposal in this proceeding is an attempt to ensure that the cost savings from consolidation benefit the Acquireds as well as legacy customers.

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[385] *Decision and Order* (EB-2013-196/187/198 - Hydro One - Norfolk MAAD), July 3 2014, p.12

[386] *Ibid*, p.14

6.2.20 ***EB-2014-0244 – Haldimand MAADs, and EB-2014-0213 – Woodstock MAADs***. These two proceedings, arising in the wake of the Norfolk decision, ended up being relitigation of the same issues, and with the same results.

6.2.21 The two decisions essentially affirm the policy evolution signaled in the Norfolk decision, and in fact strengthen it. In the Woodstock case, for example, the Board made the reporting of cost savings, and the allocation of those savings between customers, a condition of approval:

> That Hydro One reports on the following, until Hydro One applies for new rates for existing Woodstock customers:
>
> a) All costs (including overhead corporate costs) associated with serving the Woodstock service area, recorded and reported both on an annual and cumulative basis from the time of the closing of the share purchase transaction
>
> b) Actual savings achieved (being the difference between the total costs in a) and the costs of Woodstock as a stand-alone utility)
>
> c) Indication of how those savings have or will be allocated.[387]

6.2.22 ***EB-2016-0276 – Orillia MAADs.*** Despite the clear indications of Board policy, Hydro One in the current proceeding proposed substantial increases to the rates for the former customers of Norfolk, Haldimand, and Woodstock. The increases can be summarized in the following table[388]:

Original Proposal for Acquired Rate Increases

Acquired Utility	*Class*	*Volume*	*2013/4 Total*	*Proposed 2022 Rates (Monthly)*			*Increase*
				Fixed	*Variable*	*Total*	
Norfolk	AR	570	$34.72	$41.17	0.0000	$41.17	18.58%
	AGSe	2182	$89.69	$42.92	0.0199	$86.34	-3.73%
	AGSd	161	$780.99	$252.30	6.3239	$1,270.45	62.67%
Haldimand	AR	694	$34.08	$41.17	0.0000	$41.17	20.80%
	AGSe	1819	$60.60	$42.92	0.0199	$79.12	30.56%
	AGSd	143	$741.13	$252.30	6.3239	$1,156.62	56.06%
Woodstock	AUR	600	$26.70	$31.60	0.0000	$31.60	18.35%
	AUGe	2695	$67.16	$35.68	0.0206	$91.20	35.79%

[387] *Decision and Order* (EB-2014-0213 - Hydro One - Woodstock MAAD), September 11 2015, p.21

[388] Sources of data: Average class volumes for each Acquired utility, and 2013/4 total Dx bills, from Exhibit I-56-SEC-99(f); Proposed 2022 Rates from Exhibit H1, Tab 4, Schedule1, Attach 5, as filed March 31, 2017.

	AUGd	177	$461.41	$282.77	5.1984	$1,202.89	160.70%

6.2.23 It was clear that the rate increases were significant, despite the fact that the revenue to cost ratios were still less than 100% in each case.

6.2.24 In parallel, Hydro One, leveraging its offer to build the ISOC in Orillia, was proposing to purchase Orillia Power. Its application and the proposed rate structure were similar to the proposals for Norfolk, Haldimand, and Woodstock. As in the previous cases, customer groups opposed the transaction on the basis that Orillia customers would be harmed by substantial rate increases. While Hydro One argued that there would be cost savings, and there had been cost savings for the previous three, they could not get around the fact that they were proposing significant rate increases for the Acquireds.

6.2.25 The Board did not reject the transaction, however. Instead, the Board panel suspended the Orillia proceeding on the basis that the fate of the Norfolk, Haldimand and Woodstock customers was in this panel's hands, and the Orillia panel should await the outcome of this proceeding to see if it would be as bad as the customer groups claimed.[389]

6.2.26 Orillia and Hydro One moved for a review, and during that proceeding filed evidence in November 2017 that Hydro One were planning to amend their proposed rates for the Acquireds as a result of changes to cost allocation and other impacts. The review panel directed the original panel to lift their suspension and proceed with the case.[390]

6.2.27 The original panel responded by inviting Hydro One to provide further evidence, and defend their rate proposals for past Acquireds, including how those proposals would impact or inform the potential fate of Orillia customers. Hydro One did not file any additional evidence except material it had already filed.

6.2.28 The Orillia panel then determined that it would deny approval for the Orillia acquisition on the basis that they could not be satisfied that customers would not be harmed with respect to

[389] EB-2016-0276, Procedural Order No.6, July 17, 2017

[390] *Decision and Order* (EB-2017-0320 Hydro One - Orillia Motion to Review PO 6), January 4 2018

price.[391] In so determining, the Board said:

> The experience of the three acquired utilities in Hydro One's current distribution rates case is informative. In the MAADs proceedings in which Hydro One acquired these utilities, Hydro One pointed to savings that would be realized through the acquisition. Although these savings may well have occurred, they do not appear to have resulted in overall cost structures (and therefore rates) for customers of the acquired utilities that are no higher than they would have been, once the deferral period ended and their rates were adjusted to account for Hydro One's overall costs to serve them. Material filed in the Hydro One current distribution rates case shows that some rate classes are expected to experience significant and material increases. While the OEB has not approved these requested rates, this panel takes notice of the proposed rate increases which Hydro One states are reflective of the costs to service the acquired customers, and are inclusive of the "savings" that Hydro One states were realized.
>
> …
>
> As discussed above, the OEB is not satisfied that a list of forecast cost savings from the acquisition automatically results in overall cost structures for the customers of the acquired utility that are no higher than they would be without the consolidation. Hydro One has failed to make the case that the OEB can be assured that the underlying cost structures would be no greater than they would have been absent the acquisition. The OEB is therefore not satisfied that the no harm test has been met, and on this basis the application is denied. [392]

6.2.29 That decision is currently the subject of a Motion to Review and Vary brought by Hydro One and Orillia. The Board's determination of the threshold issue on that Motion is pending[393].

6.2.30 All of this case history has created guidance for Hydro One and other acquirors of Ontario LDCs. Vice-Chair Quesnelle described that guidance succinctly as follows:

> MR. QUESNELLE: I guess my point is more to the analysis that informed the Board on what it would expect in future reflection of those cost structures in rates. And I think that's what the Board said, was that there was an expectation that the underpinning costs that were demonstrated to be lower in the MAADs applications would be reflected in the rates. And I am not seeing any analysis that goes back to that same analysis that led the Board to that conclusion. [394]

6.2.31 Then, after a further back and forth with Mr. Andre, the Vice-Chair went on to say:

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[391] *Decision and Order* (EB-2016-0276 - Hydro One - Orillia Power MAAD), April 12 2018

[392] *Ibid*, p.12-13

[393] EB-2018-0171

[394] Tr.11, p171

> MR. QUESNELLE: And is there any way to combine those two exercises? Wouldn't it just be a cost much like you would have a -- and I am thinking of a comparison to the gas utilities, where they have zonal pricing. You've got a cost to deliver in a certain area and those costs are tracked, and the then there is the overlay of the corporate costs that goes across on a cost allocation basis that would have those common costs shared, but the local costs are tracked separately. [395]

6.2.32 In essence, the cases told Hydro One: "Show us that the costs to serve the acquired customers will be less than the costs to serve them without the acquisition, and then show us that those cost savings are being reflected in the rates for those acquired customers".

6.2.33 ***Evolution of the Hydro One Proposal in this Case.*** While all of this was going on, Hydro One was reviewing its proposal for the Acquireds. As a result of that review, in December it filed updated evidence that made fundamental changes to the cost allocation for the Acquireds, and therefore to their proposed rates. The result of those changes, in terms of rates, can be seen in the following summary provided by Hydro One: [396]

Woodstock	**Average Billing Determinant (kWh/kW)**	**2014 (DX Bill)**	**2021 (DX Bill)**	**Change ($)**	**Change (%)**
Residential	600	$26.70	$30.78	$4.08	15.28%
GS < 50	2,695	$67.16	$72.62	$5.46	8.13%
GS > 50	61,239/177	$461.41	$795.26	$333.85	72.35%
Norfolk	**Average Billing Determinant (kWh/kW)**	**2013 (DX Bill)**	**2021 (DX Bill)**	**Change ($)**	**Change (%)**
Residential	570	$34.72	$37.70	$2.98	8.57%
GS < 50	2,182	$89.69	$77.28	-$12.41	-13.83%
GS > 50	57,223/161	$780.99	$980.44	$199.45	25.54%

[395] Tr.11, p.173

[396] Exhibit I-56-SEC-99(f).

Haldimand	Average Billing Determinant (kWh/kW)	2014 (DX Bill)	2021 (DX Bill)	Change ($)	Change (%)
Residential	694	$34.08	$37.70	$3.62	10.61%
GS < 50	1,819	$60.60	$70.85	$10.25	16.92%
GS > 50	50,917/143	$741.13	$893.84	$152.72	20.61%

6.2.34 Hydro One's change to the proposals in this proceeding, apparently a tactical change designed to strengthen its case for the Orillia acquisition[397], has resulted in proposals that are ill-conceived and ultimately not supportable as good ratemaking.

6.2.35 SEC understands that this lengthy history may appear to be tangential to the issues directly arising in this proceeding. SEC submits, however, that the history shows that there is a longstanding problem here that is intrinsic to Hydro One and its acquisitions strategy. The issues that arise before this Board panel today are caused by those fundamental problems, and any solution that doesnot deal with them will just be a BandAid, kicking the real issue down the road for the next acquisition or harmonization hearing. At some point the issue can no longer be kicked down the road. It must be addressed.

6.2.36 In our submission, Hydro One has had many chances to deal with these problems, and has not succeeded. Reluctantly, SEC believes that it is time for the Board to step in and, in a more forceful and direct manner, ensure that this time the problem gets solved. Not only would this allow the Board to protect the 60,000 customers in Norfolk, Haldimand, and Woodstock directly affected in this proceeding, but it would also provide a framework for ensuring that the 50,000 customers in Orillia and Peterborough, and the many others served by other LDCs Hydro One seeks to acquire, can also be protected if and when the time comes. Depending on how it plays out, it may even help the Board alleviate the pain of the 136,000 customers that suffered from the 2007 harmonization.

6.2.37 In effect, SEC is proposing that the Board finish what it started in EB-2016-0276 (or maybe

[397] Hydro One denies this. See Tr.11, p.21. However, given the timing, and what was going on in the Orillia proceeding, it is difficult to believe this to be a convenient coincidence, i.e. that magically more cost reductions were found.

started in EB-2013-0244). In the Orillia case, the Board told Hydro One, and everyone else who wants to acquire a distributor: "You won't be allowed to acquire new customers if you will then penalize them in rates." In this case, the Board is in a position to express the other side of that equation: "You won't be allowed to penalize customers in rates after you acquire them."

6.3 ***Problems with the Structure of the Proposal***

6.3.1 Hydro One has proposed to set rates for the Acquireds, once their pre-agreed rate freezes have ended in 2021 and 2022, using the following approach:

- ***(a)*** Segregate the Acquireds into new classes, Urban and Non-urban, to facilitate rates that differ from the rates for all other Hydro One customers. Harmonize Norfolk and Haldimand with each other. Harmonize Woodstock with no-one for now, but perhaps other densely populated Acquireds in the future.
- ***(b)*** Establish new cost allocation rules that benefit the Acquireds, but do not apply to other Hydro One customers in essentially identical circumstances.
- ***(c)*** Set new loss factors for these rate classes that are not based on actual loss factors for those customer classes.
- ***(d)*** Use revenue to cost ratios to ensure that, even though allocated costs are high, the rates charged to these customers are no more than Hydro One's forecast of their rates had they not been acquired by Hydro One.

6.3.2 The rationale for this unusual approach, which is inconsistent with the method used in EB-2007-0681, is Hydro One's belief that the various Board decisions, starting with Norfolk, have essentially prohibited rate increases for acquired customers.

6.3.3 SEC submits that Hydro One, in designing this proposal, has jettisoned cost allocation and rate design principles in pursuit of a goal that is likely not achievable: serving these acquired customers at a cost that is less than the cost had they not been acquired. Hydro One, as a fundamentally high cost utility, is not in a position to be a lower cost utility to these customers given its current cost structure. No amount of creative use of the 'freedom and flexibility' that

Hydro One thinks it has in cost allocation and rate design[398] can make Hydro One into a lower cost service provider. A duck is a duck, and it is decidedly not an eagle.

6.3.4 ***Segregation of Acquireds.*** At the simplest level, the fact that the Acquireds are being segregated from other customers is directly contrary to the decision in EB-2005-0378. In that case, the Board made clear that harmonization into customer classes that did not have a basis in cost homogeneity would not be considered favourably by the Board.

6.3.5 That having been said, Hydro One can quite fairly state that they do not really have a choice in this, because if they assign these customers to existing customer classes, their rate increases will be astronomical. That is precisely what the Board has told them they cannot do. Assuming they cannot get their existing rates down to levels similar to other LDCs they have to set rates for the Acquireds on a different basis than their legacy customers. There is no other way around it.

6.3.6 In this respect, the following comparison of final approved annual distribution bills for 2017 may be instructive.[399] It compares Hydro One's bills for its Urban and Medium density customers to other LDCs serving 10,000 to 30,000 customers (plus Veridian and Entegrus, which each essentially serve several communities of that size). Hydro One's three recent Acquireds range from 16,000 to 22,000 customers, so this is a reasonable range, and one of the two further acquisitions that Hydro One is known to be pursuing (Orillia) is also in this size range.[400]

6.3.7 Unfortunately, Hydro One's annual distribution bills for general service customers are not competitive:

[398] Tr.10, p.191. SEC accepts that cost allocation and rate design are partly art, and partly science. At its root, though, this process is supposed to be an objective process, not an arbitrary one that is capable of being manipulated to achieve corporate objectives that have nothing to do with cost causality, or fairness.

[399] The full supporting spreadsheet has been filed with this Final Argument.

[400] Peterborough, their other publicly-known acquisition target, is just slightly larger than this range.

Annual Distribution Bill Comparison - 2017 General Service

(monthly charge and volumetric rate)

	Utility	*Residential*		*GS<50*		*GS>50*		*Overall*	*Number of*
		750 kwh	*% of Avg*	*2000 kwh*	*% of Avg*	*250 KW*	*% of Avg*	*Ranking*	*Customers*
1	E.L.K.	$219.84	66.4%	$314.16	48.2%	$7,083.90	58.9%	57.82%	12,398
2	Kingston	$296.28	89.5%	$537.48	82.4%	$10,592.88	88.1%	86.66%	27,356
3	Westario	$314.52	95.0%	$572.88	87.8%	$9,324.54	77.5%	86.79%	22,822
4	Orangeville	$314.10	94.9%	$632.52	97.0%	$8,763.78	72.9%	88.24%	11,685
5	Ottawa River	$286.74	86.6%	$573.24	87.9%	$11,469.66	95.3%	89.96%	10,820
6	COLLUS (Applied)	$304.74	92.1%	$588.60	90.3%	$11,073.12	92.1%	91.46%	16,426
7	Entegrus	$298.68	90.2%	$608.76	93.4%	$11,022.24	91.6%	91.73%	40,503
8	Veridian	$311.46	94.1%	$610.80	93.7%	$11,289.96	93.9%	93.87%	117,494
9	Essex	$313.92	94.8%	$709.56	108.8%	$9,422.58	78.3%	93.99%	28,640
10	Halton Hills	$304.56	92.0%	$578.76	88.8%	$12,466.50	103.6%	94.80%	21,534
11	Erie Thames	$363.24	109.7%	$615.48	94.4%	$10,842.12	90.1%	98.08%	18,265
12	Welland	$333.72	100.8%	$589.32	90.4%	$12,480.54	103.8%	98.31%	22,470
13	St.Thomas	$323.04	97.6%	$681.60	104.5%	$11,638.38	96.8%	99.62%	16,918
14	Wasaga	$283.62	85.7%	$545.28	83.6%	$15,990.24	132.9%	100.74%	12,985
15	Festival	$342.00	103.3%	$756.24	116.0%	$10,416.24	86.6%	101.96%	20,362
16	North Bay	$331.74	100.2%	$732.84	112.4%	$11,263.50	93.6%	102.07%	23,975
17	Grimsby	$329.70	99.6%	$753.00	115.5%	$11,544.66	96.0%	103.68%	11,038
18	Lakeland	$394.20	119.1%	$764.64	117.3%	$12,441.18	103.4%	113.25%	13,264
19	Orillia	$329.34	99.5%	$845.04	129.6%	$14,834.70	123.3%	117.46%	13,340
20	Innpower	$514.08	155.3%	$738.36	113.2%	$15,460.26	128.5%	132.35%	15,790
21	Canadian Niagara	$442.44	133.6%	$945.84	145.0%	$23,191.92	192.8%	157.16%	28,627
22	Hydro One (Urban)	$381.96	115.4%	$908.40	139.3%	$28,678.74	238.4%	164.36%	NA
23	Hydro One (Med.)	$612.24	184.9%	$1,678.44	257.4%	$49,144.56	408.5%	283.62%	NA
	AVERAGE (excl. HONI)	$331.05		$652.11		$12,029.19			

6.3.8 It is therefore clear that Hydro One will not be able to meet the Board's expectations with its existing rate classes. It must instead segregate the Acquireds into new classes.

6.3.9 The proposed approach, however, is driven by achieving a particular rate result, not by the principles of customer classification, cost allocation and rate design (including postage stamp rates for homogeneous customer groups) that this Board has accepted and required for decades.

6.3.10 ***Failure to Carry Out an Objective Analysis.*** A better approach would have been to ask the question: "How did these acquired utilities – and every other small town LDC in Ontario - serve their customers at costs substantially below the costs that Hydro One would have to allocate?" There are many possible answers[401], including:

- ***(a)*** The acquired utilities were skimping on maintaining and improving their systems, and/or on providing proper service to their customers. If that is the case, then by spending more (in terms of allocated costs), Hydro One should be able to point to improved outcomes for the Acquired customers.
- ***(b)*** The acquired utilities were making less than their allowed ROE because of political decisions affecting ratesetting.
- ***(c)*** Hydro One's overall cost structure, particularly with respect to corporate common costs, is too high relative to other LDCs.
- ***(d)*** Hydro One's cost allocation model allocates costs too heavily to customers in geographic areas like Norfolk, Haldimand, and Woodstock, in effect subsidizing other customer groups by over-allocating to customers like these.

6.3.11 To the extent that either of the first two are engaged, rates can be raised without harming the customers. If the third is engaged[402], the implication is that Hydro One must improve its cost structure, or stop buying other LDCs. To the extent that the fourth is engaged, Hydro One should review its model by reference to the costs other LDCs actually allocate to certain classes of customers in certain locations. If Hydro One says it costs $400 a year to serve a residential customer in a town of 10,000, and everyone else can do it for $250, perhaps Hydro One's allocation of costs to that town is wrong. Perhaps there is an internal inter-class subsidy that Hydro One has missed.[403]

6.3.12 The point is that, if it really does cost less to serve a group of customers that can or should be

[401] Which, of course, may existing in combination.

[402] And we already know from the benchmarking of Hydro One costs that this is likely to be true.

[403] It is in fact a bit surprising that Hydro One has not done this exercise. Every distributor in the province uses the same cost allocation model. It would not be difficult for Hydro One to compare the costs to serve customers like the Acquireds, line by line, between its cost allocation output and the output from each of the comparable distributors. Which USofA accounts are out of whack with the comparators? Why is that the case? It is even possible to go back into the allocators to find out whether the differences are initial costs, or load shapes, or age of assets, or how the model is being used, etc. What is the point of having scads of data in a common format if it is not used to provide comparative information?

treated as an identifiable class, then it usually makes sense to segregate those customers into a separate class. Of course, you would also include in that class all other customers with the same cost characteristics. If it really costs $300 to serve that residential customer in Woodstock, then you have to ask whether that would also apply to the residential customer in Brockville, or in Ancaster. And, if not, why not? What is the basis for their rates to be higher, if their costs are not higher, and their characteristics are the same?

6.3.13 Now, the likely answer here is that Hydro One cannot solve the problem of being a high cost distributor by changing its cost allocation. Its primary problem is likely the third one above – its costs are too high. However, the point is not to slag Hydro One for inability to control costs. The point is that in order to segregate customers into a separate customer class, it is important to do your homework.

6.3.14 SEC believes that the reason Hydro One does not do the sort of disciplined analysis that we are suggesting is that they suspect the answer is (c) above, and they do not want to hear it. In our view, that is unacceptable. Creating new customer classes, and then creating new cost allocation rules in order to benefit those customer classes, is not the right way to set rates. The right way is to do a thorough and objective analysis. Let the data drive the analysis. If along the way the analysis highlights problems that you do not want to hear about, the answer is not to complain, or to hide from the results. The answer is to fix those problems.

6.3.15 It may well be that some component of the cost differentials between Hydro One and the previous acquired utilities is the result of better Hydro One outcomes, and some may be the result of problems in the Hydro One cost allocation model, and some may be the result of Hydro One's cost control challenges. In order to deal with all customers fairly, Hydro One has to have that information. It does not, and as a result its proposal to establish separate classes for the Acquireds does not have a proper evidentiary and analytical foundation.

6.3.16 ***New Cost Allocation Rules.*** Instead of finding out why everyone else can serve these towns at a lower cost than Hydro One, Hydro One has proposed to jury-rig their cost allocation model to make it appear that the cost to serve the Acquireds is lower than it would have been had they not been acquired.

6.3.17 The starting point to understand what Hydro One is doing is to realize that they do not even know the cost to serve these Acquireds if the cost allocation were done on the normal basis. That is demonstrated in the following exchange:

> MR. SHEPHERD: And do you know what that number would be if you were just looking at how much they would have to bear in costs if they had the same deal as the previous acquireds?
>
> MR. ANDRE: Well, our proposal is to create new acquired classes, so if you are asking did we do a run where we moved all of these acquired into the R1 and R2 and our normal classes, no, we didn't do that.
>
> MR. SHEPHERD: So you have no idea what their costs would be if you just treated them like everybody else?
>
> MR. ANDRE: I think you'd have to be more specific about treating them as everyone else. As I said, if you are asking what the costs would have been if they moved into R1 and R2, no, we don't have that run. If you are asking what the costs would be if we didn't apply the adjustment factors, again, we haven't done that run, but that would be simply a matter of removing the adjustment factors from the model.
>
> MR. SHEPHERD: It would certainly be 10- or 20- or $30 million higher, right?
>
> MR. ANDRE: I don't know about the exact quantum, but, yes, it would be notably higher. [404]

6.3.18 It is actually not that difficult to work out the result, given that in that scenario the Acquireds would be subject to normal rates. However, that is not really relevant, because that is not the approach Hydro One took. They decided, instead, to give the Acquireds a preferred deal, i.e. rates established on a different, more favourable basis than the basis of rates for all other customers.

6.3.19 The primary way Hydro One has done this is through adjustment factors for the allocation of specific components of rate base. In the initial filing, Hydro One developed and included adjustment factors for poles, transformers and other assets that are essentially local in nature. In effect, only part of the normal rate base allocation for those categories of assets was allocated to the Acquireds. If a customer in, say Trenton was allocated $100 of rate base for poles, a (hypothetically) identical customer in Woodstock was allocated, say, $60 for poles. This was done by calculating a top-down adjustment factor (percentage allocation) for the

[404] Tr.11,p.16-17

relevant asset classes. [405]

6.3.20 In the December update, which reduced the allocations to the Acquireds substantially, the main change was to add distribution stations to the asset classes that were subject to adjustment factors.

6.3.21 The result of this cost allocation legerdemain was the following. If the plain vanilla cost allocation that would apply to these customers (if they were treated like everyone else), was $60M+ in costs:

- ***(a)*** The March filing, which included the first set of adjustment factors, reduced the costs allocated to the Acquireds to $46.2M.
- ***(b)*** The December filing, which added an adjustment factor for distribution stations, reduced the costs allocated to the Acquireds to $41.2M.

6.3.22 The reason Hydro One had to make these adjustments to their cost allocation was that they had calculated the amount the Acquireds would have been paying, had they not been acquired by Hydro One – the counterfactual - as $36.9M It was not possible to serve these customers at a lower cost than had they not been acquired if you used the normal cost allocation methodology to calculate the cost to serve them. In March 2017, Hydro One determined that getting the allocated costs down to $46.2 million would be close enough, especially if there were further adjustments to the rates themselves through the use of revenue to cost ratios.

6.3.23 When the Board panel considering the Orillia MAADs application showed concern about those costs and rates, Hydro One then reduced the costs allocated once more, which ensured that, with 80% revenue to cost ratios, the Acquireds would (arguably) pay less than had they not been acquired.[406]

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[405] This not only affects capital components of revenue requirement, but also the operating cost components of revenue requirement that are allocated based on rate base: Tr.10 p.194 and Tr.11, p29.

[406] At the 11th hour, during the oral hearing [See Tr.10,p.121 and Tr.10, p.180], Hydro One also said that the counterfactual they were using for comparison purposes – the amount they said the Acquireds would have been paying had they not been acquired – was understated in two ways. First, the depreciation was understated by $2.1 million. Second, the low voltage charges were not accounted for correctly, adding another $0.9 million. The net result is status quo bills for the Acquireds, had they not been acquired, of $39.9 million. None of this additional information has been subjected to any discovery or testing. In addition, Hydro One did not adjust its counterfactual to take account two other important impacts that have also arisen in the intervening period: the shift of working capital allowance from 15% to 7.5%, which on average reduces revenue requirement by 2%; and the shift from

6.3.24 Hydro One has been less than clear in describing exactly what these adjustment factors are. They are based on the idea that some assets are essentially local in nature. However, since Hydro One is not going to be in a position to identify which assets are actually serving these customers[407], Hydro One has estimated the differences in costs between the actual assets serving these customers at a snapshot in time, and the assets that would have been allocated at that time under the normal cost allocation model.

6.3.25 What is this differential – the adjustment factor – actually capturing? There are three possibilities:

> ***(a)*** OEB Staff believes that it is a form of "direct allocation" of the assets serving these customers.[408] That is, it is a physical delineation of the actual assets serving these particular customers, and these customers simply need less assets to serve them (for whatever reason).
>
> ***(b)*** Another possibility is that this adjustment factor is intended to capture the fact that the assets serving these customers are relatively older than the assets serving the rest of Hydro One's customers. Thus, they would have been depreciated longer, and even if the quantity of poles, transformers and stations was the same, the net book value would be lower.
>
> ***(c)*** A third possibility is that the adjustment factor captures the difference in cost between Hydro One acquiring an asset, and another LDC acquiring an asset. Hydro One is known to be a high cost distributor. If Hydro One and another LDC have identical assets, it may be that the Hydro One assets have a higher cost. Thus, the assets serving the Acquireds may have simply been less costly, even if they are the same quantity and age.

6.3.26 SEC must confess that we are not able to determine, which if any, is the purpose of the adjustment factors. The way Mr. Andre describes it, it could be any of these three explanations:

> When we looked closer at the costs that were being allocated to the acquired

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CGAAP to MIFRS, which on average reduces revenue requirement by 3-4%. If the Acquireds had not been acquired, those two impacts would have applied, with a likely impact (reduction) of more than $2 million.

[407] As evidenced by exchanges between the witness and both Member Elsayed and Vice-Chair Quesnelle: Tr.11, p.168-9; 174-6. See also Tr.10, p.197

[408] OEB Staff Submissions, p. 156

> utilities, what we noticed was that the amount of distribution stations that were being allocated was significantly higher than the actual distribution station asset costs for the acquireds. [emphasis added][409]

6.3.27 Hydro One says that, in the foreseeable future, it does not intend to change the adjustment factors.[410] That suggests a permanent differential between actual assets and allocated assets, implying that the OEB Staff assumption is correct. On the other hand, it also begs the question why these customers need less assets to serve them than customers in other similar areas. If the customers in Norfolk can be served with 60% of the major assets than Hydro One would need to serve similar customers, you would think that Hydro One would want to know why (and perhaps implement some changes to achieve a similar result throughout their system).

6.3.28 Hydro One has in fact provided no evidence to suggest that it actually requires less units of poles, transformers and stations to serve the Acquireds.

6.3.29 Hydro One also says that, when all of the existing assets serving these customers have been replaced at Hydro One cost levels, the adjustment factors could be revisited.[411] This suggests that the third explanation for the adjustment factors is the most correct. It also, of course, implies that, sooner or later, these customers are going to be harmed by being acquired by Hydro One.

6.3.30 Finally, Hydro One also suggests that some of the assets acquired were older, and this was a factor in creating the adjustment factors. This implies the second explanation may be correct. However, that would also imply that, to maintain correct cost allocation, Hydro One would have to account for the replacement of assets, and therefore the reductions in the age differential, in calculating the adjustment factor going forward. They have no intention of doing so.

6.3.31 SEC submits that, as long as Hydro One insists that it cannot maintain separate records of the assets being used to serve the Acquireds, OEB Staff cannot be correct in its assumption that

[409] Tr.11, p.21. See also Tr.10, p.189

[410] Tr.10, p.198

[411] Tr.10, p.119

this is a form of direct allocation of assets.

6.3.32 Direct allocation is used, for example, when a dedicated feeder and station is used to connect a large customer. It serves no-one else, only that customer. It would be possible to allocate the assets used to serve each town directly as well, as long as separate records were being kept. That is not what Hydro One is doing. Direct allocation of assets to serve particular towns might benefit places like Trenton or Brockville or Smiths Falls, in terms of reducing their rates, but it would also mean different rates for every municipality served by Hydro One. Hydro One has never suggested doing that, and it is not suggesting it here.

6.3.33 What Hydro One is in fact doing is saying that the previous owners of the acquired utilities served those customers with a certain fixed amount of assets. In doing so, it has to be treated as a going in cap for Hydro One, whether it is fair or not.[412] If the other customers of Hydro One have to bear a higher share of those costs as a result, so be it. This therefore has nothing to do with direct allocation. It has to do, instead, with artificially reducing the costs allocated to the Acquireds so that it looks like Hydro One can serve them for the same as, or less than, their previous owners.

6.3.34 What Hydro One is seeking to demonstrate to the Board, however, is not factually correct. Hydro One cannot serve these customers at a lower cost than if they had not been acquired. The fact that they have to successively reduce the cost allocation to these customers, and still cannot get down to the status quo level, is proof of that.

6.4 ***Equity Between Customers***

6.4.1 ***Special Cost Allocation Rules.*** The reason the cost allocation adjustments matter is that they are fundamentally unfair. This is a rate harmonization exercise, and it is helpful to remind ourselves of the purpose of rate harmonization:

> Harmonization is a utility process aimed at ensuring that all of a utility's customers share fairly in the utility distribution costs.[413]

6.4.2 When SEC brought up fairness during the oral hearing, Hydro One objected, saying that

[412] See Tr.10, p.196-7

[413] *Decision with Reasons* (EB-2005-0020/0378 - Hydro One Dx 2006), April 12 2006, p.53

whether the previous Acquireds had been treated fairly was not really a live issue in this proceeding[414]. We agree, but that is surely not the point.

6.4.3 There are two general issues of equity arising in these cost allocation proposals.

6.4.4 First, cost allocation is a zero-sum exercise. If you allocate less costs to one customer class, other customer classes have to pay those costs. Every dollar not being allocated to the Acquireds is being paid by other customers who, under the normal cost allocation principles, would not have to bear those costs.

6.4.5 Second, and more important, perhaps, is the basic cost allocation principle that like customers be treated the same. Hydro One is, quite deliberately, rejecting that principle in this case.[415] The Acquireds, they say, must get a special, sweeter deal than their other customers, because the Board told them that's what they have to do. That is captured in the following exchange:

> MR. SHEPHERD: And so the people in Smiths Falls, for example, they pay the full amount of all these things. There's no adjustment for them, right?
>
> MR. ANDRE: Yes, that's correct.
>
> MR. SHEPHERD: And the people in Trenton, and the people in Thorold, they all pay the full -- I am trying to understand why, aside from the fact that the Board is getting tougher with you about acquireds, I am trying to understand why the cost allocation to these acquireds is fair and the cost allocation markedly different for the old acquireds is also fair. Which one is no longer fair?
>
> MR. QUESNELLE: Mr. Shepherd, I think Mr. Vegh made an objection to that line as to whether or not the original acquired costs are fair. Those are acquired entities now. They are customers of Hydro One, and have been for twelve years.
>
> I recognize -- I think it's valid to have the comparison of the methodology and point to the differences. But at this juncture, I think the evidence that has been given is that there was a conversation and there were Board decisions back in 2006.
>
> MR. SHEPHERD: Mr. Chairman, if Mr. Andre answers my question that the current cost allocation is fair, then that's the end of it. By implication, the old one is unfair, but you're right, there's nothing we can do about it.

[414] Tr.11, p.19-20

[415] Tr.10, p.199-200

> But if his answer is neither of them is fair, or there's a balance, or they're fair in different ways, then I think this Board should hear it because that relates to these acquireds.
>
> MR. QUESNELLE: In that context, Mr. Andre.
>
> MR. ANDRE: I think the allocation to the three acquireds that we have now follows the Board's underlying principles that are in the cost allocation model. There are certain costs that are allocated based on number of customers and weighted number of bills, and that is the same as it always has been.
>
> And then on top of that, we've adjusted -- we have made an adjustment to what the model would normally allocate to be consistent with the direction that the Board has provided with respect to setting rates for these three acquired classes as part of their MAAD decision. [emphasis added] [416]

6.4.6 SEC notes that this has nothing whatsoever to do with relitigating the treatment of the previous acquired customers. While Thorold, Trenton and Smiths Falls are part of the previous Acquireds, Ancaster and Sudbury and Kingston, and many others, are not. The same issues arise for all of these customers.

6.4.7 Rate harmonization is about fairness. Indeed, cost allocation is about fairness. The whole basis on which customers are classified and then costs are allocated is the principle that like customers are treated alike, and different customers are treated appropriately differently, all on the basis of cost causality. While there is undoubtedly some judgment as part of the process, it is fundamentally an objective analysis.

6.4.8 In this case, Hydro One is saying to the Board that it told them they have to give these new customers a better deal, i.e. treat their existing customers – whether previously acquired or long term legacy customers – unfairly.[417]

6.4.9 That is not, it is submitted, what the Board told Hydro One to do. The Board did not tell Hydro One that it should throw out the basic principles of customer classification and cost allocation. In fact, in discussing the zonal rates of the gas utilities, Vice-Chair Quesnelle was a lot closer to what the Board's guidance intended. Union Gas has separate rates for different rate zones, because it actually has quite different costs to serve those rate zones. It keeps track

[416] Tr.11, p.23-25

[417] Tr.10 p.200

of those separate costs, and charges the customers in each rate zone the actual costs to serve them.[418]

6.4.10 When Hydro One charges a customer in Trenton, or in Ancaster, a lot more than it charges a virtually identical customer in Simcoe (Norfolk) or in Woodstock, it is not because the costs to serve those customers are different. It is because Hydro One cannot serve customers at cost levels as low as every other LDC in the province. If Hydro One does not somehow adjust its cost allocation so it at least looks like its costs are lower for those newly acquired, it will be shut out of the LDC acquisition market until it can show that it will not be harming its acquired customers.

6.4.11 If, on the other hand, it is true that it actually costs less to serve the customers in Woodstock than the cost allocation model would suggest, then it is almost certainly true that it costs less to serve the customers in Kingston, and in Brockville, and in many other municipalities, than the cost allocation model would suggest. In that case, the proposed rates for all of those other municipalities, whether acquired or not, would not be just and reasonable.

6.4.12 SEC submits that the proposed new rate classes for the Acquireds must be rejected by the Board. If they are in fact fair to the Acquireds, then by definition the rates proposed for many other customers of Hydro One are not fair, and cannot be approved by the Board.

6.4.13 ***Revenue to Cost Ratios.*** In addition, it must not be forgotten that the rates for several of the proposed new rate classes are proposed at low revenue to cost ratios[419]. This is necessary because, even with all of the adjustment factors, the allocated costs to these new classes are still higher than the counterfactual, no acquisition by Hydro One. The result is that, after reducing the allocated costs down to $41.2M for the Acquireds, Hydro One is proposing to collect from them $34.9M, and to continue that state of affairs indefinitely into the future.[420]

6.4.14 This raises a further issue of equity and fairness between customers.

[418] Alectra is currently doing the same thing thus it is possible. .

[419] "80% for most classes": Tr.10, p.183

[420] Tr.10:, p.68

6.4.15 The problem is that rate design is also a zero-sum exercise. If customers in Simcoe have their rates set at an 80% revenue to cost ratio, the rates for other customers must be set to recover more than 100% of allocated costs.

6.4.16 This, of course, is perfectly normal in the ordinary course of business. The Board has established ranges because cost allocation is still not a perfect science, and because allocated costs often change from one rebasing to the next.

6.4.17 In this case, however, the use of the low revenue to cost ratios is not to recognize cost uncertainties, or to reflect ups and downs of cost allocation over time. It is, instead, a deliberate attempt to reduce the rates of one group of customers at the expense of another group of customers.[421] If, for example, Toronto Hydro's existing streetlighting rates recovered 100% of the costs allocated to that class, but Toronto Hydro wanted to reduce that to 80% to give the City of Toronto a break, the Board, and the other customers, would have none of it.

6.4.18 Yet, that is exactly what is happening here, and it is not a fair approach to rate design.

6.5 ***Sustainability***

6.5.1 Hydro One proposes to use the new acquired rate classes to incorporate other acquisitions in the future. Two of those proposed acquisitions are already known, so it is possible to assess whether this model is feasible for those customers. The following is a bill comparison for those utilities, and the proposed Hydro One rates:

[421] See Tr.10, p.151-4.

Annual Dx Bill Comparison
(monthly charge and volumetric rate)

	Utility	*Residential*	*GS<50*	*GS>50*
		750 kwh	*2000 kwh*	*250 KW*
1	Peterborough (2016)	$267.00	$584.76	$10,045.44
2	Orillia (2017)	$329.34	$845.04	$14,834.70
3	Hydro One (AU 2022)	$379.08	$752.88	$12,886.20
4	Hydro One (AG 2022)	$464.28	$912.48	$17,431.32
5	Hydro One (Urban)	$381.96	$908.40	$28,678.74
6	Hydro One (Medium)	$612.24	$1,678.44	$49,144.56

6.5.2 Thus, even with the cost allocation adjustment factors, and the 80% revenue to cost ratios, Peterborough customers would likely get rate increases on harmonization. Some Orillia customers, on the other hand, might get rate decreases. That is, Woodstock customers would have to get rate increases to average out the higher Orillia costs.

6.5.3 That assumes, however, that the adjustment factors remain the same. One would think they would have to change, though, since new assets from Peterborough and Orillia would be integrated into the cost allocation and therefore into the calculation of the adjustment factors.[422]

6.5.4 It also assumes that the 80% revenue to cost ratios continue indefinitely into the future. Even if the Board's ranges remain as broad as they are currently, which we think is unlikely, it does not seem to be sustainable to charge one group of customers only 80% of the cost to serve them over the long term.

6.5.5 Of course, Orillia and Peterborough are only being used as hypotheticals. Although there is currently a motion for review in Orillia, as of right now that acquisition is not going through. As for Peterborough, the last news was that Hydro One and Peterborough had broken off their agreement in principle, but then were talking again. It is very possible that the ability of Hydro One to acquire those utilities, or any others, will depend in part on the outcome of this proceeding.

[422] See Tr.10, p.120

6.5.6 The point is two-fold.

6.5.7 First, Hydro One can only use this new model if the adjustment factors and the low revenue to cost ratios remain. If not, their costs and rates would still be too high to bring in new acquisitions like these and serve them at lower cost than their current owners.

6.5.8 Second, in any case there would be rate adjustments, both to the new Acquireds, and to the Acquireds in this proceeding (Woodstock, Norfolk and Haldimand). Because the number of customers in these new acquisitions may be large relative to the numbers of customers in the proposed new classes, rate impacts can and will affect both groups of acquired customers, likely materially, unless further ways of adjusting the cost allocation are proposed at the time. There will be winners and losers. Some customers will be harmed. There does not seem to be a way of avoiding that result.

6.6 ***Options Available to the Board***

6.6.1 The Acquireds currently have approved rates they are being charged by Hydro One. The Board is being asked to harmonize those rates into the Hydro One rate structure, and along the way approve rate increases for those customers. The Board would appear to have four options available to it at this time.

6.6.2 ***Approve the Hydro One Proposal.*** The Board could, as OEB Staff has proposed, approve the proposal of Hydro One, creating six new rate classes, increasing rates (in some cases substantially) for the Acquireds, and jettisoning the basic principles of customer classification, cost allocation, and rate design.

6.6.3 For the reasons outlined above, including in particular the long term damage that the Hydro One proposal does to the Board's principled approach to just and reasonable rates, and the fundamental unfairness of the Hydro One proposal, SEC believes that this option is not a reasonable one. It is not, in our view, sufficient for the Board to hold its nose and say, "Let's get on with it", as it did in EB-2007-0681.

6.6.4 ***Deny Approval.*** The Board always has the option of just saying no. This would mean that the

rates for the Acquireds would remain frozen, as they are today and will in any case continue to be until 2021. If the Board denies approval, Hydro One would then have a couple of years to figure out another alternative to the proposal they have made, and present that alternative proposal to the Board.

6.6.5 This is not an unreasonable option.[423] The status quo is going to continue for a couple of years anyway. Hydro One has provided the Board with a flawed and unsound harmonization proposal (not the first time they have done that), and has not supported that proposal with appropriate evidence. Since there are no immediate consequences of saying no, the Board can do so and wait for a better proposal from Hydro One.

6.6.6 The problem with this is that Hydro One does not have a good track record in harmonization. Its first major harmonization was rejected by the Board. The next time around the harmonization was strongly criticized by the Board, but in the end approved, subjecting many customers to high rate increases. In the four MAADs applications between then and now, Hydro One has shown intense reluctance to face its own cost issues, and how that affects acquisitions. Now, in this proceeding, the utility made a bad proposal, then changed it for no apparent reason, and even then at the last minute had to find some additional costs for the counterfactual in order to avoid looking like they were overcharging the Acquireds.

6.6.7 The Deny Approval option requires the Board to rely on Hydro One to figure out an approach to acquisitions and harmonization of acquired customers that works. It is not surprising that customers, including SEC, have little confidence in Hydro One doing that.

6.6.8 ***Ring Fence the Acquireds.*** SEC raised during the hearing, the Brampton paradigm[424], and Vice-Chair Quesnelle followed up on that option, looking for ways the Acquireds, and maybe future Acquireds, could be treated as if they were a separate rate zone or separate LDC within Hydro One.

6.6.9 This has many of the same problems as the Hydro One proposal. If it is unfair to allocate

[423] In essence, that is what the Board did in EB-2005-0378.

[424] Tr.11, p.30-4

costs to Woodstock customers using different rules than for Kingston, that is still true if the Woodstock customers are in a separate, or virtual, utility, as opposed to simply a different rate class. The Kingston customers will legitimately ask, why can't we be in that rate zone, since it would more accurately reflect our costs too?

6.6.10 The ring fencing also does not solve the problem of the long term use of low revenue to cost ratios, which would have to be true here as well for the rates to be at or below the rates in the counterfactual.

6.6.11 In any case, it would appear that the use of ring fencing is not open to the Board. Even before this Board has had a chance to make its decision on the Hydro One proposal, Hydro One has effectively forced the issue by ending maintenance of separate cost records for the Acquireds.[425] Even if making the Acquireds into a separately costed rate zone was at some point a viable option, the horse has already left that barn. Hydro One no longer has the records to implement it.

6.6.12 ***Take Charge.*** The fourth option, and the one SEC proposes, is that the Board should take charge of the situation, in three steps:

> ***(a)*** Deny approval of the six new rate classes.
>
> ***(b)*** Direct Hydro One to commission an external analysis of their acquisition and harmonization strategies, with a view to identifying solutions that are conceptually sound, fair to all customers, both existing and new, and reasonably likely to be applicable to future acquired customers.
>
> ***(c)*** Until Hydro One has presented that study to the Board, and a new, reasonable harmonization approach has been approved, continue the current decoupling of the rates of the Acquireds from costs. Starting in 2021, escalate their rates annually by the weighted average rate increase applicable to all other Hydro One customers as approved by this Board.

6.6.13 This option is basically a more proactive version of the Deny Approval option. Instead of relying on Hydro One to go back to the drawing board and do a better job, the Board would

[425] Tr.11, p.168-9

provide specific direction in what Hydro One has to do.

6.6.14 This proposal has two key elements.

6.6.15 First, the Board should stipulate that Hydro One get external experts to do the analysis. Hydro One has to date been relying on internal resources for its acquisitions and harmonization policies. This has not worked. Just as Hydro One benefitted from going outside the organization on vegetation management, so too Hydro One could benefit from a new set of expert eyes on this longstanding set of problems.

6.6.16 Second, the Board should stipulate a deep dive into the real problems facing Hydro One on this score. As noted earlier, the problems here are not just about harmonization. Hydro One has an acquisition strategy that results in Hydro One buying lower cost distributors. If the cost differentials were small, the savings from the acquisitions might be sufficient to make up the difference. Unfortunately, the cost differentials between Hydro One and other Ontario distributors are not small, and to date Hydro One has not been able to find economies of scale sufficient to overcome those differentials. Acquired customers will be served at higher cost after acquisition.

6.6.17 That does not mean that Hydro One must exit the acquisition business, although that is certainly one of the options that should be explored. It does mean, however, that the external analysis must look not just at what happens after a distributor is acquired, but also how acquisitions are identified and negotiated, and the cost-benefit analysis used by Hydro One in that process. Once another distributor is purchased, it is too late for Hydro One to say "Oops, we can't serve these guys at a lower cost after all".

6.6.18 SEC also believes that the Board should put in place rate adjustments for the Acquireds, at least in the short term. They have existing rates, and they will have those existing rates in 2021, when their rate freezes end.

6.6.19 SEC proposes that, until Hydro One comes back with an external analysis of the situation, and a harmonization approach for the Acquireds and future acquisitions that is based on sound principles, and still meets the "no harm" test, the rates of the customers in Norfolk, Haldimand

and Woodstock should be escalated, starting in 2021, by the same percentage that the rates of all other Hydro One customers are being escalated. For example, if the overall weighted average increase for all of Hydro One's customers in 2021 was 2.4% under the Board-approved Custom IR plan, then the rates for the Acquired would increase in 2021 by 2.4% from their existing levels. This would not deal with the underlying rate differences (the solution for which must await the results of the analysis), but would ensure that on an incremental basis both existing and Acquired customers are treated fairly.

6.6.20 SEC also believes that Hydro One should not be allowed to acquire other distributors until such time as it has a principled, and Board-approved, harmonization methodology in place that is consistent with the no harm test. While we recognize that this Board panel does not have the jurisdiction to so order, we believe it would be helpful for the Board to signal to Hydro One that this is likely to be the case.

6.7 ***SEC Recommendations***

6.7.1 Hydro One has proposed that it will import the costs of the Acquireds, as well as their billing determinants, into its totals in 2021 for cost allocation and rate design purposes. Their method of doing so is the creation of new rate classes.

6.7.2 That integration of costs and billing determinants only works if there is a viable method of setting rates for existing and acquired customers going forward. There is not, so in SEC's view the costs and billing determinants of the Acquireds should remain separate until an acceptable rate harmonization approach is approved by the Board.

6.7.3 The Board should deny approval of the Hydro One proposal, but take a more active role in ensuring that Hydro One can come up with a better plan.

6.7.4 SEC therefore submits that the Board should adopt the fourth option above, denying approval of the new rate classes, and directing a process that will lead to solutions to these underlying problems, which have been plaguing the Board, Hydro One and, most importantly, the customers for many years.

7 OTHER

7.1 *Effective Date*

7.1.1 Hydro One is seeking an effective date for its rates of January 1, 2018. Based on the oral hearing dates and the argument schedule, it is likely that rates cannot be implemented before January 1, 2019 at the earliest.

7.1.2 It is the responsibility of a regulated utility to file their application for a rate change with sufficient time before a proposed effective date to allow the Board, acting reasonably, to conduct a hearing and issue a final decision. That is the basis of the Board's general practice that rates are effective immediately after the Board's decision and rate order.

7.1.3 While SEC accepts that Hydro One is not responsible for some of the delay in the hearing of the application, its filing date of March 31, 2017 was insufficient for a proceeding of this size to be completed, and rates to be put in place, by January 1, 2018.

7.1.4 Hydro One would have known that its filing date was insufficient based on its own past experience. It filed its previous 5-year distribution application in December 2013, seeking rates beginning in 2015. Even then, the Board did not render a decision until March, with a rate order in April of 2015.[426]

7.1.5 With that information, at the very least Hydro One should have filed its application in December of 2016, more likely September 2016. It would have known that 9 months is not sufficient for a five year application for the largest electricity distributor in the province. Thirteen months – as it previously assumed - should have been the bare minimum, and based on its last rate order, seventeen months would have been more reasonable.

7.1.6 SEC submits that as a result, the Board should set an effective date no earlier than May 1, 2018.

[426] *Rate Order* (EB-2013-0416 - Hydro One Dx 2015-2019), April 23 2015; *Decision (*EB-2013-0416 - Hydro One 2015-2019), March 12 2015, p.66

7.1.7 If the Board does order an effective date before the implementation date, Hydro One's position is that the period over which the foregone revenue should be collected is best determined in the rate order phase since the parties and the Board will be able to look at the impacts of the decision on customer bills.[427] SEC agrees with this approach, as long as there is sufficient opportunity for parties to provide comments during the rate order phase. SEC notes its preference is likely an approach which allows for the smoothing of any rate impacts.

7.2 ***Costs***

7.2.1 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

_____

Mark Rubenstein
Jay Shepherd
Counsel for the School Energy Coalition

[427] Tr.10, p.86