PALIARE ROLAND
BARRISTERS

Richard P. Stephenson
T 416.646.4325 Asst 416.646.7419
F 416.646.4301
E richard.stephenson@paliareroland.com
www.paliareroland.com

August 10, 2018

File 93901

VIA *RESS* FILING AND COURIER

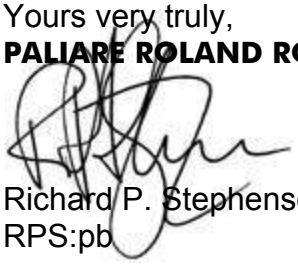
Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli,

Re: Hydro One Networks Inc. 2018-2022 Distribution Rates
EB-2017-0049

Attached please find the Power Workers' Union's Submissions with respect to the above-noted application.

Yours very truly,
PALIARE ROLAND ROSENBERG ROTHSTEIN LLP



Richard P. Stephenson
RPS:pb

Encl.

Doc 2594368 v1

EB-2017-0049

IN THE MATTER OF the Ontario Energy Board Act, 1998;

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.

Submissions of the Power Workers' Union

1. The following are the Power Workers' Union's ("PWU") submissions on the issues reviewed in the matter of Hydro One Network Inc.'s ("Hydro One") 2018-2022 distribution custom IR application.

2. These submissions do not specifically address all issues on the issues list. Where an issue has not specifically been addressed, the PWU supports the application as filed, and supports and adopts the submissions of Hydro One in support of the application.

A. GENERAL

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

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

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

3. With the aid of Ipsos, Hydro One conducted a customer engagement process that took place primarily in June and July of 2016,[1] more than two years ago. Ipsos undertook telephone surveys, online workbooks, focus groups, and workshops to elicit

[1] Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1, Pages 26-43 of 317

feedback for Hydro One to consider in designing an appropriate investment plan to support this distribution rate application.[2]

4. This engagement process was described as a "key element" of the application and was a significant determinant in the level of capital investment embedded within the application. Hydro One stated that its decision to move from its Plan A investment plan, which was recommended by Hydro One management to its Board on October 11, 2016[3], to the Plan B-Modified investment plan was directly in response to the Board's concerns arising from the outcomes of the customer engagement.[4] This is further discussed in Section D of this submission.

5. The application cited a portion of the Renewed Regulatory Framework for Electricity ("RRFE") which states that utilities are to "…demonstrate consideration of all relevant factors, including the needs of existing and future customers and the costs to meet them, and that planning has been informed by appropriate engagement…".[5] Though Hydro One made a reasonable effort to adhere to this portion of the RRFE, the introduction of the Fair Hydro Plan ("FHP" or *Fair Hydro Act, 2017*) after the customer engagement process was completed greatly diminishes the validity of the outcomes of the engagement. The engagement did not sufficiently take all relevant factors, including the costs to ratepayers of meeting current and future customer needs, into consideration.

6. The FHP was officially announced on March 2, 2017. This was well after the customer engagement process which took place in the summer of 2016. Though the HST rebate portion of the FHP came into effect in January 2017, the majority of the plan was not implemented until June 1, 2017, after Hydro One originally submitted this application.

7. The FHP is designed to reduce the typical bill by 25% for residential and small business customers across Ontario. The reduction is predominantly through

[2] Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1, Page 4 of 317
[3] Exhibit I, Tab 3, Schedule SEC-4, Attachment 2
[4] Hearing Transcript, Volume 1, June 11, 2018, Page 82, lines 10-14 &
Hearing Transcript, Volume 4, June 15, 2018, Page 160, lines 14-20
[5] Exhibit B1-1-1, DSP Section 1.3, Page 4 of 21 - Ontario Energy Board, Renewed Regulatory Framework for Electricity, October 2012, Section 2.5

adjustments to the Regulated Price Plan ("RPP") and the removal of the amount recovered from ratepayers of the Ontario Electricity Support Program ("OESP"), the Ontario Rebate for Electricity Consumers ("OREC"), and a large share of the Rural or Remote Electricity Rate Protection ("RRRP") program.[6] Since the average Hydro One customer consumes more than the "typical" customer the average reductions are even greater than 25%.

8. Another important feature of the FHP is the expansion of the OESP. More residential customers are now eligible for bill reductions through the OESP and the credits have increased by 50%.[7] A portion of OESP credits are provided based on the necessity of electricity for providing heat, which is disproportionately the case for Hydro One customers that do not have access to natural gas heating.

9. The FHP also created two new programs that are particularly relevant to Hydro One residential customers: the Distribution Rate Protection ("DRP") program and the First Nations On-reserve Delivery Credit. The DRP limits the base distribution charge paid by over 770,000 R1 and R2 residential customers.[8] The base charge is currently $36.43 and will remain at that level until it is changed by the Ontario Energy Board. With this program, the typical Hydro One rural residential customer's bill decreased by 31%, or approximately $50 per month.[9] The First Nations On-reserve Delivery credit fully off-sets distribution and transmission costs previously charged to First Nations ratepayers.

10. Hydro One provided information to its customers with respect to the benefits of the FHP after it was announced but did not engage in further customer consultations as it related to this application:[10]

> **MR. STEPHENSON: So needless to say, regardless of the specific details, you understood that the Fair Hydro Plan had a -- was designed to and did have a material impact on R1 and R2 customers' bills and rates, correct?**
>
> **MR. PUGLIESE: Yes, correct.**
>
> **MR. STEPHENSON: And in fact, you guys put out a lot of customer information back to them about the benefits that they were going to get out of this, right?**

[6] Ontario Energy Board, Fair Hydro Act, 2017 - https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017
[7] https://ontarioelectricitysupport.ca/FAQ
[8] 770,602 R1 & R2 customers as of 2016 - Exhibit I, Tab 3, Schedule PWU-1, Part b
[9] Undertaking JT1.08, Attachment 2, Page 15 of 36
[10] Hearing Transcript, Volume 4, June 15, 2018, Page 164, lines 9-28

MR. PUGLIESE: Correct.

MR. STEPHENSON: Okay.

MR. NETTLETON: Mr. Pugliese, could you speak closer to the mic? I think the court reporter is having difficulty.

MR. PUGLIESE: Sure.

MR. STEPHENSON: But we know you did not go back out, Hydro One did not go back out and do any re-do of its customer engagement in 2017, when it was armed with the information regarding the effect of the Fair Hydro Plan, right? That didn't happen?

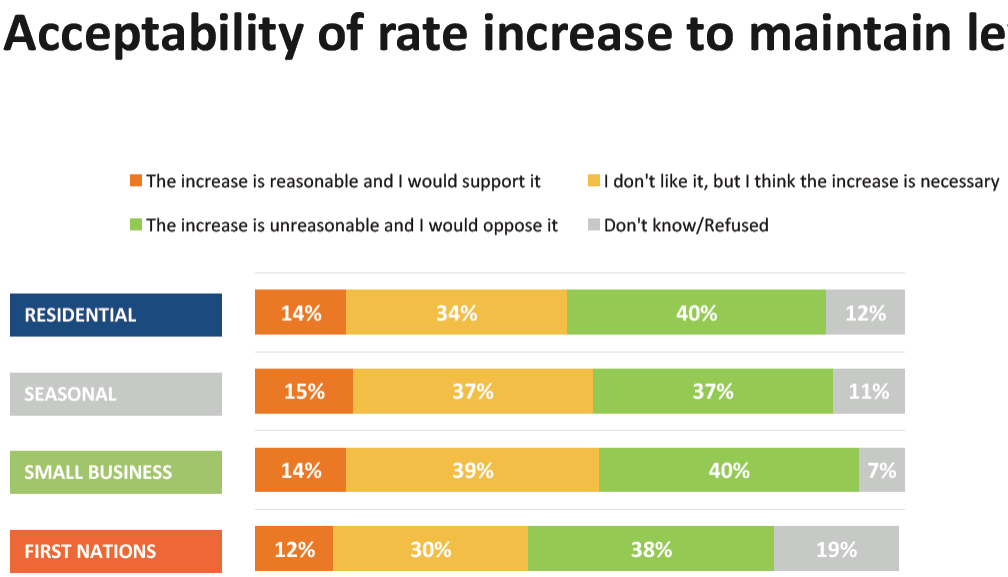
MR. PUGLIESE: Correct.

11. The PWU submits that the significant impacts on customer bills stemming from the FHP warranted further customer consultations. Hydro One made changes to this application since it was originally filed in March 2017. There were two updates to the application: a comprehensive update filed June 7, 2017, after the FHP was implemented; and Exhibit Q filed December 21, 2017 which included significant changes to the vegetation management program. There was a six-month period between these updates in which customers could have been consulted with the FHP in effect. The PWU notes that Hydro One revised certain other elements of the application directly as a result of the FHP, including working capital and bad debt expense.[11]

12. Ipsos' consumer engagement aided Hydro One in developing its investment plan by providing insights into customers' priorities and preferences with respect to the allocation of spending. Customers were asked to prioritize items such as reducing the number of outages, reducing the length of outages, upgrading the system, and improving customer service. This portion of the engagement process provides Hydro One with the knowledge of how their customers' view various trade-offs and how to most efficiently meet customer needs with a given level of investment. The other key segment of the engagement concerned the willingness of customers to pay higher rates for improved reliability and the corresponding level of investment required.

[11] Exhibit I, Tab 33, Schedule Staff-179

13. Though the results vary between customer groups and survey channels, a slim majority of residential and small business customers is willing to accept the rate impacts necessary to maintain reliability. The results are summarized in the following Ipsos chart:[12]



14. The costs faced by Hydro One ratepayers have significantly changed with the implementation of the FHP. Residential and small business customer bills are materially lower than they had been in the summer of 2016 when the customer engagement took place. The context of questions put forward to ratepayers concerning incremental bill impacts and related reliability impacts has meaningfully changed since the summer of 2016. It is not simply the relative cost (a $2 increase) that matters to ratepayers, it is the absolute amount of their total bills.

15. Responses from ratepayers were provided within the context of the impact on their total bills at the time of the consultations that are now substantially lower. Prior to the FHP, Hydro One's bill impacts statements show that a typical R1 customer's total bill would have been $163.83.[13] Subsequent to the FHP, the same customer's total bill would be $122.38.[14] The PWU submits that asking ratepayers if they would accept a $2 increase to each of these bills is two different questions and these questions would elicit

[12] Exhibit B1, Tab 1, Schedule 1, Section 1.3, Attachment 1, Page 300 of 317
[13] Exhibit H1, Tab 4, Schedule 1, Attachment 1, Page 7 of 45
[14] Exhibit I, Schedule 4, Tab PWU-004, Attachment 2, Page 7 of 45

different responses. It is inappropriate to interpret the results of the customer engagement devoid of the context of a customer's total bill.

16. The introduction of the DRP further diminishes the relevance of the customer engagement results. Mr. Merali confirmed in the oral hearing that Hydro One's R1 and R2 customers would not face rate increases as a result of this application:[15]

> **MR. STEPHENSON: And you -- but you were aware that customers were sensitive about this trade-off between rates and reliability, right? That was something that was -- you asked them very specifically about, right?**
>
> **MR. PUGLIESE: Yes.**
>
> **MR. STEPHENSON: And for your R1 and R2 customers, the Fair Hydro Plan changes that calculus, doesn't it?**
>
> **MR. MERALI: Yes, it does.**
>
> **MR. PUGLIESE: It does.**
>
> **MR. STEPHENSON: You could spend more on reliability in the near-term, 2017, '18, '19, '20, et cetera, and those customers would not see that, at least not for the time being, correct?**
>
> **MR. MERALI: Correct.**

17. The DRP eliminates any actual rate increases faced by the majority of Hydro One customers. For Hydro One's R1 and R2 customers, the DRP severs the link between Hydro One's actual costs (and the revenue requirement approved by the Board) and those customers' electricity bills. Rather, the distribution rates paid by those customers will now be determined based on a formula prescribed by regulation.[16] As a consequence, there is no validity to the analysis regarding the willingness of ratepayers to pay incremental amounts in rates since most ratepayers will not in fact be paying those higher rates. If a question was put forward to ratepayers regarding their willingness to accept no rate increase for improved reliability, the response would have been entirely different.

[15] Hearing Transcript, Volume 4, June 15, 2018, Page 165, lines 1-14
[16] Ontario Energy Board, Fair Hydro Act, 2017 - https://www.oeb.ca/newsroom/2017/fair-hydro-act-2017

18. In an exchange with the PWU, the customer care panel agreed that the results of the customer engagement process would be different if the consultations were held today:[17]

> **MR. STEPHENSON: Let me make this suggestion to you. I mean, you've spent a lot of time on this subject of customer engagement; it's your thing. I respect that.**
>
> **But as informed as you are regarding your customers' needs, isn't it -- wouldn't you anticipate that if you went out to your customers, and I'm now talking about R1 and R2, and you told them we know -- we understand that you would like increased reliability, and we understand that you're concerned about your rates going up, under the Fair Hydro Plan, we can give you increased reliability and not have your bills go up. Do you think that's a good idea?**
> **What do you think the answer they'd give you?**
>
> **MR. MERALI:[18] I suspect you'd get a different result.**
>
> **MR. STEPHENSON: They'd say yes, I'll sign up right now, won't they? That's what they're going to say, right?**
>
> **MR. MERALI: I think we'd have different results if we did it again today.**
>
> **MR. STEPHENSON: A different result meaning the one I just said, right?**
>
> **MR. MERALI: Correct.**
>
> **MR. PUGLIESE: I'm not sure. We haven't done the survey.**
>
> **MR. STEPHENSON: Wait a minute, though, come on. This is your business. Like you're out there, and your job is to know your customers. Are you telling me you don't know your customers?**
>
> **MR. PUGLIESE: I'm saying we have a variety of channels to which we are informed about what our customers think, and this is one.**
>
> **MR. STEPHENSON: I mean, let's not play cat and mouse around this. Are you telling me that you think your – you don't know that your customers -- if you gave them the option of improved reliability at no higher bill, they're not going to think that's a good idea?**
>
> **MR. PUGLIESE: They probably will think it's a good idea.**

19. The FHP has greatly improved the affordability of electricity to Ontario residential and small business ratepayers. The reduction in RPP commodity rates, elimination of the provincial portion of HST, and removal of program costs from regulatory charges significantly reduce total electricity bills to ratepayers across the province. The DRP and

[17] Hearing Transcript, Volume 4, June 15, 2018, Pages 167-168, lines 6-28 & 1-13
[18] Transcript erroneously attributes this sentence to Mr. Morris of the Finance & Compensation panel

OESP expansion in particular have a significant impact on electricity costs faced by Hydro One ratepayers.

20. The PWU submits that the introduction of the FHP invalidates the results of the customer engagement process. Mr. Merali and Mr. Pugliese testified in the oral hearing that they would expect the results to be different if the consultations were held after the introduction of the FHP. The executive vice president of customer care, Mr. Pugliese, went beyond that notion and agreed that customers would think that a higher level of investment today would be "a good idea".[19] As the results of the customer engagement process were the basis for moving from Hydro One management's suggested Plan A investment plan to the Plan B-Modified investment plan, and the results are no longer valid, it would not be reasonable to conclude that the Plan B-Modified investment plan best reflects customer preferences.

21. The PWU notes that Board Staff's submission on the customer consultation process places significant focus on cost concerns without acknowledging the impact of the FHP.[20] Ironically, their submission also suggests the absence of consideration of the reliability impacts stemming from the new vegetation management program, which was also outlined subsequent to the consultation period, make the customer consultation inadequate.[21] The new vegetation management program, which is discussed later in this submission, is at an early stage of implementation and the resulting reliability impacts are unclear at this time. The FHP, on the other hand, has already been implemented and the resulting impacts on bills are already being experienced by the majority of Hydro One's customers. The PWU submits that any evaluation of changes to reliability impacts since the customer consultations cannot be made without considering the more significant cost impacts.

22. With the FHP in place there will be no time in the foreseeable future in which electricity bills will be more affordable than they are today for the majority of Hydro One customers. The PWU submits that deferring necessary investments to a later period, by moving from the Plan A investment plan to Plan B-Modified, is unfair to future

[19] Hearing Transcript, Volume 4, June 15, 2018, Page 168, lines 12-13
[20] OEB Staff Submission, Page 55
[21] OEB Staff Submission, Page 62

ratepayers as the costs of the incremental investments are likely to be incurred to a greater extent by ratepayers in the future than by ratepayers today.

23. The FHP has provided an opportunity for Hydro One to make the necessary investments today to avoid a costly and foreseeable investment bulge in the future. It would be imprudent and violate the principles of intergenerational equity to continue to defer investments as the number of high risk assets continues to increase and higher proportions of assets near their end of service lives. The PWU submits that investment Plan A is the most appropriate investment plan to meet the needs of current and future ratepayers at the lowest overall cost. These issues are further discussed in Section D of this submission.

B. CUSTOM APPLICATION

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

Issue 9: Are the values for the proposed custom capital factor appropriate?

24. Hydro One proposes to use a custom capital factor as part of its custom incentive rate methodology. The custom capital factor is used with a revenue cap index that is based largely on Toronto Hydro's price cap index approved in EB-2014-0116.[22] The custom capital factor represents the incremental capital investments in the latter years of this Custom IR application.

25. The custom capital factor is derived based on Hydro One's capital investments required to support its proposed distribution system plan. The use of a revenue cap index and custom capital factor does not fundamentally change the structure of a custom IR application but rather allows the incremental revenue to be expressed within the typical I-X formula.

26. The proposed revenue cap index has a number of advantages over the price cap index approved for Toronto Hydro given Hydro One's unique circumstances. The integration of the Acquired Utilities in 2021 is conceptually simplified by adding the additional revenue requirement to Hydro One's existing revenue requirement.

[22] Exhibit A, Tab 3, Schedule 2, Page 2 of 12

Integration of the Acquired Utilities necessitates a new cost allocation process that will not uniformly impact the existing rate classes. Under a price cap index the rates for each class would likely have to be reset at that time to account for the change in allocated costs. Aside from adding the additional revenue in 2021, annual mechanical adjustments can be made consistently throughout the term of the application using a revenue cap index.

27. Similarly, the elimination of the Seasonal Rate Class and transition to fully-fixed residential rates would likely require additional adjustments to the price cap formula had the price cap index been used. Overall, the proposed revenue cap index allows for more consistent and conceptually more straightforward annual adjustments than would be possible with a price cap mechanism.

28. The PWU submits that the custom capital factor and revenue cap index are appropriate and consistent with the OEB's Rate Handbook.

D. DISTRIBUTION SYSTEM PLAN

Issue 23: Was the customer consultation adequate and does the Distribution System Plan adequately address customer needs and preferences?

Issue 24: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of distribution assets, service quality and system reliability?

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

I. Introduction

29. Hydro One states that its Distribution System Plan ("DSP") reflects Hydro One's plan to appropriately prioritize and pace capital investments over the 2018 to 2022 period which will align:[23]

[23] Exhibit B1, Tab 1, Schedule 1, DSP Section 1.1, Page 1 of 23

(a) customer needs to keep rates as low as possible and a preference to maintain current service levels;

(b) asset needs driven by condition and compliance requirements; and

(c) rate impacts.

30. Hydro One further explains that its approach has been shaped by: (i) a thorough investigation of opportunities to reduce its costs and increase efficiencies; (ii) ensuring investments support specific customer feedback on needs and preferences; and (iii) reducing or deferring investment levels to align customer rate impacts and potential impacts on reliability.[24]

31. Essentially, Hydro One's view is that the DSP and hence the proposed investment plan – Plan B-Modified – is a result of an iterative process intended to strike a balance between reliability (investment need considerations and asset condition) on one hand and rate impacts on customers as expressed by customers through a formal customer engagement initiative which Hydro One undertook in June and July of 2016 on the other.

32. Based on the results of this formal initiative and customer feedback that Hydro One received in its day-to-day operations, Hydro One concluded that keeping costs as low as possible is the top priority of its customers whereas maintaining reliable electricity service is a secondary priority.[25]

33. Following the formal customer engagement initiative, Hydro One developed three candidate investment plans for consideration by its senior leadership team which were reviewed by Hydro One's Board of Directors. In developing these alternative investment plans, Hydro One assessed the reliability impacts of varying investment levels for rights-of-way (vegetation management), pole replacement and stations because these three investment areas are the most significant, predictable drivers of reliability.[26]

[24] Exhibit B1, Tab 1, Schedule 1, DSP Section 1.1, Page 2 of 23
[25] Attachment 1 of DSP, Ipsos, Distribution Customer Engagement Report: Development of Distribution Investment Plan August 2016, Pages 146-147 (Section 1.3).
[26] Exhibit A, Tab 3, Schedule 1, Page 14 of 36

34. The three alternative investment plans were:[27]

- **Plan A** recommended by the Company's management, would improve reliability and the overall condition of the system, and would result in a 7.1% rate increase in 2018 over 2017 and an average annual rate increase of 3.8% over the Term.

- **Plan B** prepared to reflect an option that offered a smaller reliability improvement and marginal improvements in the overall asset condition of the system, would have resulted in a 6.2% rate increase in 2018 over 2017 and an average annual rate increase of 3.5% over the Term.

- **Plan C** would achieve the lowest possible 2018 rate increase while ensuring continued compliance with Hydro One's regulatory obligations, but would likely result in significantly reduced reliability and further deterioration in the overall condition of the system. Plan C would have resulted in a 5.0% rate increase in 2018 over 2017, and an average annual rate increase of 2.8% over the Term, and was not supported by the Company's asset managers because of the risk to the system.

35. Hydro One also notes that the 2018 rate increases associated with all three of these investment plans reflect some factors that were not entirely within the company's immediate control in developing those plans. For example approximately half of the rate increase is caused by changes in the load forecast (due to external factors such as conservation and demand management, and economic conditions) and the settlement of existing regulatory accounts.[28] Consequently, the large non-controllable component of the rate increase required Hydro One to consider aggressive deferrals of certain investments and significant efficiency initiatives in order to prepare investment plans that are consistent with the outcome of the customer engagement process, which highlighted the importance to customers of keeping cost increases to a minimum.

36. The investment plan that Hydro One has proposed is none of Plans A, B, or C but what is called Plan B-Modified. Hydro One states that its management, which had recommended Plan A, provided a revised Plan B investment level that would maintain current reliability in response to concerns raised by its Board of Directors.

> **Senior management therefore challenged planners to continue to investigate a plan that would further mitigate cost increases but still reflect responsible**

[27] Exhibit A, Tab 3, Schedule 1, Page 15 of 36
[28] Exhibit A, Tab 3, Schedule 1, Page 15 of 36

> **stewardship of the assets and no degradation in reliability over the full Term. In particular, managers were challenged to consider how to mitigate the significant rate increase in 2018**.[29]

37. As a result, an adjusted investment portfolio with a forecasted 2018 rate impact of 5.4%, "Plan B–Modified", was developed to maintain overall forecasted system reliability at current levels, while continuing to offer discrete power quality and reliability improvements for certain segments of the network.[30]

II. The Proposed Investment Plan: Plan B-Modified

38. Plan B-Modified is therefore derived from Plan B. The adjustments made to Plan B are expected to reduce the total term projected capital expenditures by $51 million or approximately 7.5% when compared to the original Plan B.[31] The reduction in capital expenditures in turn is achieved through, among other things, a reduction of spending on wood pole replacements, station refurbishments, component replacements, system capability reinforcement, information technology and facilities and real estate to minimize rate impacts and offset the effects of a reduced load forecast, accepting short-term, small-scale reliability impacts where appropriate.[32]

39. It is important to note that Hydro One's asset planners and management, in their submission to Hydro One's Board of Directors dated, October 11, 2016, had rejected Plan B and recommended Plan A.[33] In fact the submission, the purpose of which was to seek feedback from the Board of Directors, proposed only two alternative investment planning scenarios – Plan A (Recommended) and Plan B (Not Recommended). There are two points worth noting about the two planning scenarios submitted to the Board of Directors in the October 11, 2016 document.

40. First, Plan A and Plan B referenced in the document are the same Plan A and Plan B that are presented and discussed throughout Hydro One's Application:

[29] Exhibit A, Tab 3, Schedule 1, Page 15-16 of 36
[30] Ibid.
[31] Exhibit A, Tab 3, Schedule 1, Page 17 of 36, lines 23-24
[32] Exhibit A, Tab 3, Schedule 1, Page 17 of 36
[33] Exhibit I-3-SEC-4, Attachment 1

MR. STEPHENSON: … And just to be clear, the Plan A and Plan B that are referenced here are the same Plan A and Plan B that are discussed subsequently that are part of the four options, correct?

MR. D'ANDREA: That's correct.[34]

41. Secondly, at the time of the submission of the document to the Board of Directors, Hydro One had already finalized its customer engagement report and in fact the document included discussion of the outcomes from the customer engagement process. In other words, Hydro One had already heard from customers that keeping costs as low as possible was their top priority. Therefore, Hydro One management already understood customers' concerns and rate impacts when it recommended Plan A and not Plan B.

42. Plan A was recommended because:[35]

- Investments are paced to avoid potential catch-up in future investment periods;
- It increases the number of pole replacements, distribution station refurbishments, and submersible cable replacements to address the poor results of condition assessments;
- It increases the number of mobile unit substations to reduce customer interruptions due to planned maintenance and refurbishment activity;
- It includes investments that are designed to improve customer satisfaction, and enable productivity and efficiency improvements to lower OM&A costs;
- It addresses identified needs and preferences of industrial customers for reliability and power quality improvements.

Plan B was not recommended because:[36]

- It presents limited opportunities for productivity and reliability improvements;
- Asset replacements would fall behind targeted levels, increasing the likelihood of unplanned equipment outages that cause customer interruptions, higher replacement costs than a planned replacement and a future "step change" in asset renewal volumes;

[34] Hearing Transcript, Volume 1, June 11, 2018, Page 79, lines 9-13
[35] Exhibit I-3-SEC-4, Attachment 1
[36] Ibid.

- Network Operating portfolio reduces funding for investment in Outage Response Management System enhancements, which may delay customer restoration improvement initiatives;

- It puts at risk the company's ability to implement various enabling IT enhancements that are designed to result in productivity savings or improved customer satisfaction;

- Lower expenditures in Fleet services will result in reduction of heavy equipment replacements of up to 13 units per year which will increase the risk of downtime hours; that will cause delays in work programs, impacting costs and performance;

- Realization of savings projections and unit cost reductions are at risk due to reduced funding levels for IT improvements;

- Reduction in 2017 for PCB Transformer replacements requires a future program increase to meet the 2025 target of elimination of PCBs, with an increased risk of potential oil leaks.

43. Hydro One testified that the merits and concerns relating to Plan A - Recommended and Plan B - Not Recommended identified in the document were valid then and valid now:[37]

> **MR. STEPHENSON: Okay. The concerns -- well, let's put it this way. The merits of Plan A and the concerns regarding Plan B, I take it that those merits and those concerns were valid then and are valid now. It's -- there were other factors that led to the change in thinking, correct?**
>
> **MR. D'ANDREA: Well, it was the factors that we tried to balance; again, customer needs, system requirements and rate impacts.**
>
> **MR. STEPHENSON: Fair enough. But what's written down in this document is accurate? Those were the validly stated merits of Plan A and the validly-stated concerns of Plan B. Leaving aside the issues that were ultimately decided, but as far as this document goes, Hydro One is still of the view that it is a fair and accurate description of those -- of the matters set out therein?**
>
> **MR. D'ANDREA: That's correct.**

44. Furthermore, the difference between Plan B and Plan B-Modified was that Plan B-Modified had less capital spending embedded in it, and therefore it is reasonable to

[37] Hearing Transcript, Volume 1, June 11, 2018, Pages 79-80, lines 28 & 1-16

conclude that Plan B-Modified would have all of the concerns identified in the document with respect to Plan B and more:[38]

> **MR. STEPHENSON: Okay. So the concern expressed in this document about Plan B was that it didn't have enough activity and it did didn't have enough spending, correct?**
>
> **MR. D'ANDREA: Correct.**
>
> **MR. STEPHENSON: Okay. And so all of those concerns would also be true of Plan B modified, fair?**
>
> **MR. D'ANDREA: Correct.**

45. The consequence of selecting Plan B-Modified is that Hydro One will have to defer capital spending and hence work that Hydro One recommended under Plan A. Even worse is that Hydro One is proposing less capital spending under Plan B-Modified than the one under Plan B - Not Recommended. Plan B-Modified included adjustments compared to Plan B, one of which is:[39]

> **A deferral of some 2018 capital spending on wood pole replacements, station refurbishments, component replacements, system capability reinforcement, information technology and facilities and real estate to minimize rate impacts and offset the effects of a reduced load forecast, accepting short-term, small-scale reliability impacts where appropriate.**

46. This was also confirmed by Hydro One's witness during cross-examination:[40]

> **MR. STEPHENSON: And whenever you had – the consequence of going for Plan B modified is that certain spending that was proposed and recommended under Plan A is deferred; correct?**
>
> **MR. D'ANDREA: That's correct.**
>
> **MR. STEPHENSON: And in fact, that was one of the risks identified in Plan B; correct?**
>
> **MR. D'ANDREA: Correct.**

47. Yet Hydro One asserts that Plan B-Modified is the appropriate investment plan:

> **Plan B-Modified is the investment plan that most effectively aligns customer needs and preferences, responsible asset management, and bill impacts. Plan**

[38] Hearing Transcript, Volume 1, June 11, 2018, Page 82, lines 3-10
[39] Exhibit A, Tab 3, Schedule 1, Page 17 of 36
[40] Hearing Transcript, Volume 1, June 11, 2018, Page 83, lines 11-18

B-Modified maintains system health and reliability at current levels without further degradation, albeit without material improvement to the overall system.[41]

48. The PWU submits this assessment of Plan B-Modified by Hydro One is problematic on three grounds.

49. First, it is inconsistent with Hydro One's evidence that its assets are getting older and poorer in condition, a subject the PWU discusses under Section IV – Capital Expenditure and Asset Management – of this submission.

50. Secondly, the evidence is clear that the single factor behind Hydro One's decision to move from Plan A-Recommended to Plan B-Not Recommended and ultimately to Plan B-Modified is the concern over rate/bill impacts on current customers.[42]

MR. STEPHENSON: Okay. And the Board's concern is fundamentally a rate impact concern and a bill impact concern, fair?

MR. D'ANDREA: Well, they looked at reliability as well.

MR. STEPHENSON: I understand that, but they -- and they struck a balance, fair?

MR. D'ANDREA: Correct.

MR. STEPHENSON: But just to be clear, Plan B modified results in less reliability than either Plan B or Plan A, right?

MR. D'ANDREA: Correct.

MR. STEPHENSON: But the Board considered it to be an acceptable trade-off, fair?

MR. D'ANDREA: Fair.

51. The concern over rate/bill impact on current customers is therefore the reason why Plan B-Modified is selected and why certain capital work programs identified under Plan A and Plan B are being deferred. The work being deferred, however, the need for that work is not going away and will have to be paid for by future rate payers, which is inconsistent with the principle of inter-generational equity.[43]

MR. STEPHENSON: Okay. So the bottom line is that all of that deferred spending is going to be -- let's put it this way: The deferred work, the deferred work is

[41] Exhibit A, Tab 3, Schedule 1, Page 18 of 36
[42] Ibid., Pages 82-83
[43] Hearing Transcript, Volume 1, June 11, 2018, Pages 83-85, lines 19-28, 1-28 & 1-15

going to be done sooner or later; it's just going to be done, relatively speaking, later, correct?

MR. D'ANDREA: Well, we were asked to look at pacing of our investment, so, yes, that's what we were doing.

MR. STEPHENSON: It's going to happen later, correct?

MR. D'ANDREA: Correct.

MR. STEPHENSON: Okay. So the first point is: Doesn't that create an intergenerational equity problem that future ratepayers are going to be faced with the cost of that work that really should be done now?

MR. D'ANDREA: I can't say what will happen in the future, because we are trying to continuously be productive and find efficiencies, so it is our goal to manage those investments, manage the pacing, and find better ways to do the work.

MR. STEPHENSON: Okay. Mr. D'Andrea, let's get real here. Are you telling me that future ratepayers are going to get this work for free because you are going to be that much more efficient? Let's get real.

MR. D'ANDREA: I didn't say it was for free.

MR. STEPHENSON: Okay. So they are going to pay for it. So doesn't that create an intergenerational equity problem? You are asking later people to pay for work that should be done now.

MR. D'ANDREA: Well, we have been asked to look at -- we have to strike the right balance, and we would have to do the same decision in the future, so we would have to look at the rate impact and the investment and the reliability. Are we deferring -- are we –

MR. STEPHENSON: Well, I understand that --

MR. D'ANDREA: -- deferring the work? Yes, we are deferring --

MR. STEPHENSON: Right. Okay.

MR. D'ANDREA: -- work --

MR. STEPHENSON: But for the rate impact you'd be doing it now, right? There is no doubt about it.

MR. D'ANDREA: Well, most of the rate increase that is we are seeking for are capital-related. They are already capital-related. If you look at what we've done in terms of what's driving our rates, our OM&A is generally flat, 5 less than inflation

MR. STEPHENSON: I -- I --

MR. D'ANDREA: -- so it is a capital issue.

MR. STEPHENSON: -- agree with you --

MR. D'ANDREA: It is a capital issue.

MR. STEPHENSON: It is this incremental amount, and the question is: Who pays for it? Is it paid for by current ratepayers or is it paid for by future ratepayers? And you've made a choice. It's future, yes?

MR. D'ANDREA: To the extent we've deferred it, yes.

52. The PWU submits that where needed work is deferred solely for the purposes of near-term rate impact considerations, and not for any valid operational reason, the consequence is intergenerational inequity. That does not mean that the deferral is inappropriate, *per se*. It does mean however, that there must be a countervailing benefit which justifies the cost shifting. The sensitivity of current customers to rate impacts will rarely, if ever, provide this justification. To accept it as a justification is to give primacy to current rate concerns over the equally valid rate concerns future ratepayers will undoubtedly have (in the complete absence of any evidentiary basis for doing so). This is expediency, not justification.

53. Thirdly, part of Hydro One's Board of Directors' concern about rate impact arose by virtue of the feedback that Hydro One received when it did its customer consultation about its proposed planning. However, as discussed earlier Hydro One's customer consultation and Hydro One Board of Directors' decision to approve Plan B-Modified occurred before the implementation of the FHP. As a result, the PWU submits, the feedback that Hydro One obtained through its customer engagement process is significantly incomplete and outdated.

54. Given the significant rate relief that the FHP has offered to most of Hydro One's customers [See Section III below], the PWU submits that Hydro One should have updated its evidence so that it reflected the reality brought about by the FHP. As indicated earlier, Hydro One made other changes in response to the FHP, including changes to its working capital requirements and bad debt expense.[44]

III. Customer Engagement, Rate Impact and the Fair Hydro Plan

55. The evidence before the Board is that the bill impacts calculated for the purpose of the current application do not reflect the actual impact on the bills received by

[44] Exhibit I, Tab 33, Schedule Staff-179

residential and small commercial customers that are subject to distribution charge reductions under the FHP. As confirmed by Hydro One, the regulation under the FHP requires that commodity prices need to be adjusted until 2022 to keep bill increases in line with inflation.[45]

56. In response to a set of PWU interrogatories, Hydro One provided the rate classes that benefit from bill protection pursuant to the terms of the FHP.[46] Hydro One responded that R1 and R2 customers specifically benefit from the DRP program as set out in the FHP. The R1 and R2 rate classes together represented 60% and 57% of Hydro One's customers and distribution revenue, respectively, in 2016.[47] Hydro One also noted that there are certain aspects of the FHP that benefit customers of all distributors in Ontario, including: (i) reduced Global Adjustment charges and the OREC credits for residential and low volume general service customers, (ii) reduced regulatory charges (OESP charge eliminated, RRRP charge reduced) and (iii) lower eligibility threshold for the Industrial Conservation Initiative program so more large general service customers can participate.

57. In response to a request by the PWU under Exhibit I, Tab 4, Schedule PWU-4, Hydro One refiled the bill impact tables and attachments in Exhibit H1, Tab 4, Schedule 1 applying the FHP elements that were in effect at the time of filing in June 2017. Below is an excerpt of the bill impacts with respect to the R1 and R2 rate classes that account for 60% and 57% of Hydro One's customers and revenue requirement, respectively:

2018

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2017 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.03	($0.73)	-1.96%	$0.20	0.24%
	Typical	750		$122.38	($0.65)	-1.75%	$1.13	0.92%
	Average	920		$141.00	($0.61)	-1.66%	$1.58	1.12%
	High	1,800		$237.41	($0.42)	-1.14%	$3.91	1.65%
R2	Low	450		$91.24	($1.38)	-3.64%	($0.52)	-0.57%
	Typical	750		$124.88	($1.37)	-3.63%	$0.10	0.08%
	Average	1,152		$169.97	($1.37)	-3.62%	$0.93	0.55%
	High	2,300		$298.72	($1.36)	-3.59%	$3.30	1.10%

[45] Exhibit I, Tab 4, Schedule PWU-3, g
[46] Exhibit I, Tab 3, Schedule PWU-1, a-e
[47] Exhibit JT 3.22-2, a

2019

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2018 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%

2020

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2019 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.50	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.58	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.32	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.72	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.98	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.90	$0.00	0.00%	$0.00	0.00%
	High	2,300		$302.01	$0.00	0.00%	$0.00	0.00%

2021

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2020 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.23	$0.00	0.00%	($0.06)	-0.07%
	Typical	750		$123.50	$0.00	0.00%	($0.12)	-0.10%
	Average	920		$142.58	$0.00	0.00%	($0.14)	-0.10%
	High	1,800		$241.32	$0.00	0.00%	($0.28)	-0.12%
R2	Low	450		$90.72	$0.00	0.00%	($0.04)	-0.04%
	Typical	750		$124.98	$0.00	0.00%	($0.06)	-0.05%
	Average	1,152		$170.90	$0.00	0.00%	($0.09)	-0.05%
	High	2,300		$302.01	$0.00	0.00%	($0.19)	-0.06%

2022

Rate Class	Consumption Level	Monthly Consumption (kWh)	Monthly Peak (kW)	2021 Total Bill	Change in DX Bill ($)	Change in DX Bill (%)	Change in Total Bill ($)	Change in Total Bill (%)
R1	Low	400		$84.17	$0.00	0.00%	$0.00	0.00%
	Typical	750		$123.39	$0.00	0.00%	$0.00	0.00%
	Average	920		$142.44	$0.00	0.00%	$0.00	0.00%
	High	1,800		$241.04	$0.00	0.00%	$0.00	0.00%
R2	Low	450		$90.68	$0.00	0.00%	$0.00	0.00%
	Typical	750		$124.92	$0.00	0.00%	$0.00	0.00%
	Average	1,152		$170.80	$0.00	0.00%	$0.00	0.00%
	High	2,300		$301.83	$0.00	0.00%	$0.00	0.00%

58. The numbers in the tables reveal that:

- Total bill impacts for 2018 (R1 and R2) range from a decrease of -0.57% for Low level consumers to an increase of 1.65% for High consumers. The distribution portion of the bill for all levels of consumption actually decreases, ranging from -1.14% to -3.64%. According to Hydro One, the reason why total bill for High level consumers in the group showed a slight increase despite the decrease in the distribution portion of the bill for all levels of consumption is due to the impact of the proposed 2018 Retail Transmission Service Rates ("RTSRs") which are higher than the current RTSRs.[48]

- For the rest of the test period (2019-2022), changes in both the distribution portion of the bill and total bill for customers in the R1 and R2 rate classes (of all levels of consumption) amount to 0% (frozen) with the exception of 2021 when in fact the change in total bill is negative. Hydro One explained this negative change saying that the proposed 2021 RTSRs are lower than the 2020 RTSRs, which result in a decrease to the R1 and R2 total bills in 2021.[49]

59. It is clear that the distribution portion of the bill and total bill impacts for the R1 and R2 rate classes that account for 60% of Hydro One's customers are zero or below zero as a result of the protection provided by the FHP.

60. Moreover, depending upon what happens to the rate of inflation and, in particular, depending upon the level of the increase of Toronto Hydro distribution rates - the prescribed proxy customer under the Act - all protected customers in Ontario, including R1 and R2, may get reductions in their commodity costs in the future to offset increases in distribution rates. This is the case because under the FHP, commodity costs are prescribed by statute for people on standard service. This is confirmed in the following exchange between counsel for the PWU and Mr. Andre:[50]

> **MR. STEPHENSON: So if Toronto Hydro's distribution rates go up more than the rate of inflation, as I understand it, the commodity cost for all Ontario customers under that prescribed commodity cost will decrease by the difference between the Toronto Hydro distribution increase and inflation, correct?**
>
> **MR. ANDRE: Yes, I see what you're saying now. Yes, that's my understanding of how it would work. I think -- I don't know if we've had an occasion to see that being implemented. In fact, I do -- it has, the first change...**

[48] Exhibit JT 3.22-2, b
[49] Exhibit JT 3.22-2, c
[50] Hearing Transcript, Volume 1, June 11, 2018, Pages 89-90, lines 16-28 & 1-7

MR. STEPHENSON: Coming up?

MR. ANDRE: No, the first change came up in May where there was reference to it. So yes, I think in principle I would agree with you, Mr. Stephenson.

MR. STEPHENSON: So again, that exerts a downward influence on R1 and R2 customer bills, correct?

MR. ANDRE: Certainly, yes. They pay electricity, so to the extent that electricity prices are reduced for all customers in Ontario, then R1 and R2 customers would also see that benefit.

61. Counsel for the PWU asked Hydro One's witness why Hydro One did not revisit their decision to select Plan B-Modified when the evidence is that 60% of Hydro One's customers would not face any rate impacts. The response from Mr. Andre was that there is concern over rate impact on the remaining 40% customers that are not covered by the Distribution Rate Protection plan under the FHP:[51]

MR. STEPHENSON: Yes. But wouldn't you agree with me that at least for R1, R2, the 60 percent of your customers, 57 percent of your revenue, they get the system they need and deserve, right? That's what Plan A says, and they are not facing the rate impact.

Like, who puts the hand up for those guys and says they're better off. You know what, maybe we should do the right thing for those people. I understand that our other customers are going to face some costs, but why do the other customers -- why does the tail wag the dog? Why is the 40 percent governing for the 60 percent?

MR. ANDRE: It's -- Mr. Stephenson, my answer isn't going to change. As I said, they represent 60, but the other 40 percent of the customers see the impact.

It's the answer that I've given. I'm not sure that I can give you anything new.

MR. STEPHENSON: Okay, so the 60 percent are the losers here.

62. Taking Mr. Andre's answer at face value, the important point here is that there is no evidence that Hydro One even asked itself the question that was begging to be answered – what is the appropriate balance between the rate concerns of Hydro One's non-protected customers,[52] relative to the rate impact free benefits available to R1 and R2 customers? By failing to ask itself the question, Hydro One allowed its non-R1 and R2 customers win by default.

[51] Hearing Transcript, Volume 1, June 11, 2018, Page 93, lines 9-26

[52] Of course all of Hydro One's customers (the R1/R2 group and the non-R1/R2 group) would experience the reliability and system benefits associated with Plan-A. The only difference is that the non-R1/R2 group would see the rate impacts associated with those benefits, and the R1/R2 group would not.

63. The PWU notes that in addition to R1 and R2, the acquired utilities - Norfolk, Haldimand and Woodstock - are receiving certain benefits from the FHP but are not eligible to receive DRP. However, the distribution rate for these acquired utilities is already frozen until 2021 by the OEB, with an additional 1% reduction, as part of the MAAD application approvals. This was confirmed by Hydro One:

> **d) Hydro One confirms that the OEB approved a 5-year base distribution rate freeze (with an additional 1% reduction) for these acquired utilities. As described in Exhibit I-3-PWU-1, while the acquired customers are receiving certain benefits from the FHP, they are not eligible to receive Distribution Rate Protection.[53]**

64. Moreover, the Board has rules and rate mitigation mechanisms in place to be applied when certain customer classes face significant rate increases. In this regard, Hydro One's evidence shows that without even considering the FHP, the total bill impacts across most rate classes resulting from the revenue requirement, regulatory asset disposition and rate harmonization requested in this Application are below the 10% value established by the Board in the 2006 Electricity Distribution Rate Handbook for customers with typical consumption. As a result, no bill impact mitigation is required.[54] Hydro One has identified the classes for which some form of mitigation is required and they are: (i) DGen customers in 2018-2019; (ii) AUGe, AUGd, AGSe and AGSd customers in 2021- 2022; and (iii) Street Light, Sentinel Light and USL customers from the Acquired Utilities. For these classes, Hydro One has proposed rate mitigation mechanisms for the Board's consideration.[55]

65. To sum up, not only R1 and R2 classes that make 60% of HO's customers but also customers of the acquired utilities will see no bill impacts resulting from the current application due either to the FHP or the Board's decision to freeze rates for the acquired utilities.

66. The consequence of selecting Plan B-Modified and not the originally recommended Plan A is that capital spending needed for asset replacement is deferred and that is, the PWU submits, irresponsible given Hydro One's aging assets - such as poles and stations - and the overall deterioration of its system.

---

[53] Exhibit JT 3.22-2, d
[54] Exhibit H1, Tab 4, Schedule 1, Page 5-6 of 8
[55] *ibid*

IV. Capital Expenditure and Asset Management

67. Investments reflected in the DSP are grouped into four categories: System Access, System Renewal, System Service, and General Plant. A summary of Hydro One's capital expenditure plan by these four categories is provided below.[56]

Table 2: 2018 – 2022 Capital Spending Forecast ($ Million)

Category	2018	2019	2020	2021	2022
System Access	154.6	157.6	160.9	165.9	170.0
System Renewal	248.6	318.7	336.7	362.5	451.1
System Service	81.8	93.4	85.6	78.8	69.5
General Plant	149.0	187.1	135.8	133.4	136.6
Total	**633.9**	**756.8**	**719.0**	**740.7**	**827.2**

68. Nearly half of Hydro One's distribution capital plan is focused on System Renewal investments where an asset's condition warrants replacement. Storm damage restoration and trouble calls, pole replacements, and distribution station refurbishments make up the bulk of activities in this category.

69. In what follows, the PWU addresses Hydro One's three largest work programs: pole replacement, station refurbishment, and vegetation management.

[56] Exhibit B1, Tab 1, Schedule 1, DSP Section 1.1, Pages 12 -15 of 23

a. Asset Management: Pole Replacement

i. Managing Pole Demography

70. Hydro One's evidence indicates that wood poles have an average expected service life ("ESL") of 62 years. Based on the current demographics of the Hydro One wood pole population, 280,000 poles (17.5% of the 1,597,000 total as at 2017) are at or beyond ESL. Hydro One expects an additional 120,000 poles reaching ESL over the next five years. There are currently 37,000 poles with no age information available.[57]

71. Hydro One proposes to replace 72,150 poles at a cost of $579M[58] over the plan period as follows:

Planned volume of poles to be replaced throughout the five year 5 period

	2018	2019	2020	2021	2022
Number of Poles Replaced	9,600	14,300	16,000	16,123	16,128

72. In response to an interrogatory by the PWU, Hydro One confirmed that at the proposed rate of replacement, the number of poles reaching ESL at the end of the plan would increase from the current 280,000 (17.5%) to 337,000 (21%).[59]

73. Similarly, Hydro One was asked in PWU Interrogatory #12b whether the average age of poles beyond ESL at the end of the plan would be older or younger than the average age of poles beyond ESL at the end of 2017:

> ***Response:***
>
> **b) At the end of the plan the average age of a pole beyond the expected service life will be older than in 2017. Based on the replacement rates in ISD SR-09 in Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 the current average age beyond the expected service life is 66 years and after the plan the age will be 68 years.[60]**

74. The Navigant Benchmarking study shows that the pole replacement rate for Hydro One (which has been an average of 10,700 poles per year over the past 5 years) is slower than for the comparison utilities, with the result that Hydro One's pole inventory is the oldest; on average, eight years older than the rest of the utilities in the

[57] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Page 37 of 89
[58] Exhibit B1, Tab 1, Schedule 1, DSP Section 3.8 -ISD: SR-09, Pages 1 -3 of 5
[59] Exhibit I, Tab 29, Schedule PWU-12
[60] Exhibit I, Tab 29, Schedule PWU-12

comparison group. This matches the planned life of poles, which is also about 10 years longer for Hydro One than for the comparison group.[61]

75. The trend in the past 5 years also shows that the volume of poles reaching ESL has been increasing year over year:[62]

Response:

a) The information on poles is presented below.

i. Please see table below for the number of poles beyond expected service life.

	2014	2015	2016	2017
Poles 62 years or older	209,653	223,673	249,231	277,950

76. In cross-examination, Hydro One's witness Ms. Garzouzi confirmed that in 2008 Hydro One had 90,000 poles that were over 62 years old and that number increased to 180,000 in 2013 (it doubled in 5 years) and it increased to 280,000 in 2017, and that number is expected to increase to 400,000 by the end of the plan period:[63]

> **MR. STEPHENSON: Okay. Here I just want to go through some evidence from your prior cases to show what's happened with your demographics, and frankly, it's -- they're going in the wrong direction, if you bear with me.**
>
> **The first place I want to go to is on the third page of the exhibit. It is page 16 of 26. And you will see here it's a chart, and if we just look at the bar on the extreme right-hand side, you will see the 60-plus, and at that point in time you were reporting -- that is ten years ago -- about 90,000 poles in that category; do you see that?**
>
> **MS. GARZOUZI: Yes.**
>
> **MR. STEPHENSON: Okay, and we can take that -- there is no reason to doubt the accuracy of this, correct?**
>
> **MS. GARZOUZI: That's correct.**
>
> **MR. STEPHENSON: Okay, just skipping ahead about four pages, we're now in the 2013 case, page 20 of 35, so this was filed in January of '14, so it would be**

[61] Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6, Page 6 of 23. It is important to understand the concept of "planned life". As clarified by Hydro One, this number does not represent any forecast as to how long the average pole will last until it fails. Rather, it is a measure of the *required* average service life, given the rate of replacement. The planned service life of Hydro One's poles is now 72 years, not because Hydro One believes that an average pole will last that long, but rather because Hydro One *needs* an average pole to survive that long given its forecast rate of replacement. Hearing Transcript, Volume 7, June 21, 2018, page 163-4.

[62] Exhibit I, Tab 29, Schedule PWU-9

[63] Hearing Transcript, Volume 7, June 21, 2018, Pages 168-171

'13 information. And so five years later, from 2008 to 2013, there is a heading, "demographics", and it says that 180,000 poles are at least 62 years old; do you see that?

MS. GARZOUZI: Yes.

MR. STEPHENSON: Okay, so in five years you went from 90,000 to 180,000, so that was -- those are worsening demographics, right?

MS. GARZOUZI: Yes, aging demographic.

MR. STEPHENSON: And it's all because your replacement rate isn't keeping up with your demographic curve, right?

MS. GARZOUZI: That's correct.

MR. STEPHENSON: Right. And so and we now know that the total number at or -- at 62 years has gone from 180 in 2013. It's now up to -- what's the current number?

MS. GARZOUZI: 280,000 and over the plan it's going to go up to 400,000.

MR. STEPHENSON: Right, so it's -- you're adding about 20,000 net new at end of service life per year over the last period of time?

MS. GARZOUZI: That's correct.

MR. STEPHENSON: And just to be clear, that's net. That's after you've taken a bunch out and replaced them, right?

MS. GARZOUZI: That's correct.

77. The fact of the matter is that the pole replacement program proposed under the Plan B-Modified, for that matter the one under Plan A-Recommended, does nothing to reverse the trend of the ever increasing volume of poles reaching ESL.[64]

MR. BOWNESS: I think what's really key here is that 62 years is where we want to be. If we were replacing -- we're comfortable with from a risk perspective. If we were staying at 62 years, that's where we feel the expected service life is in line with the replacement rate.

We know that we can't afford, our customers can't afford to keep the average age [ESL] at 62. Based on what's in plan B modified, our average age will have to be 72. That means that there is more risk within the portfolio, which means more poles are going to fail. We are not in the spot where we want to be from a risk perspective.

[64] Hearing Transcript, Volume 7, June 21, 2018, Pages 161-168

MR. QUESNELLE: I just heard you separate those two numbers; they are not the same.

MR. BOWNESS: Yes.

MR. QUESNELLE: We're not going to a new mean projected rate of 72.

MR. BOWNESS: No. And I think what would be helpful from a visual is if we could just pull up BOMA 31 for a moment again; Exhibit I, tab 35, BOMA 31, and it's page 3 Where you'll see in this chart is that with plan B 1 modified, our age our poles will need to be 72 years.

If we went all the way to plan C, which was a significant reduction, the age would have to be 107 years and that's why we're not as willing to move as far to the extreme of plan C, and that's what we presented to our board, that it's way outside the risk paradigm.

From a risk perspective, from a pure asset perspective, we don't want to be at plan B modified; we want to be at plan A. We want to be at the replacement volumes that were suggested in plan A.

MR. STEPHENSON: Plan A only gets you 6,000 more poles, right? It's not a giant different between what you are planning now.

MR. BOWNESS: So within AMPCO 27, which is tab 29 -- 17 sorry, Exhibit I, tab 29, AMPCO 27.

So plan A totals 77,400 poles over the five-year period. Plan B modified totals 72,000. And then if you go as far as plan C, which would be 45,000, that's where we get into that extreme situation of the expected service life would have to be 107 years.

…..

MR. STEPHENSON: Okay, just coming back to Plan A and Plan B modified and its effect on demographics, I think we indicated that it was about 6,000 poles different between those two in terms of replacement lights.

Just to be clear, Plan A, if you had gone to that plan, you would still have worsening demographics. That 6,000 pole difference doesn't get you -- it would get you better than 72, but it's still going to be worse than 62, right?

MS. GARZOUZI: That's correct.

78. The PWU asked what level of pole replacement would be required to maintain the current (2017) average age of poles and poles beyond ESL by the end of the plan period (2022). Hydro One, noting that poles are replaced based on condition and performance and not based on ESL or age of poles, provided the following response:

Response:[65]

a) The number of poles currently beyond the expected service life of a new pole is 280,000. To maintain this demographic, an additional 54,000 poles would need to be added to the five year plan requiring an additional $394 million in net capital.

b) The current average age of a pole that is beyond the expected service life of a new pole is 66 years. To maintain this demographic, an additional 85,000 poles would need to be added to the five year plan requiring an additional $681 million in net capital.

79. Hydro One's proposal to replace 72,152 poles over the next 5 years is solely based on condition assessment, i.e., only poles that fail a test get replaced. There is no evidence that this approach takes into consideration the role of demographics. If age is irrelevant, why would Hydro One even bother to track it?

80. The PWU submits that age demography is relevant because it has two impacts. First, there is a nexus between age and failure rates. The older a pole gets, the higher the probability that it will fail. Directionally, each year there is an increased probability. So, even if Hydro One only replaces poles that "fail tests", it is clear that it will be facing increasing numbers of poles that fail every year, i.e., Hydro One will face the "bow wave" effect.[66] The reason that other utilities included in the Navigant Benchmarking Study have a lower ESL, is not because their poles fall down sooner, but because they are proactively taken out of service before they are decrepit.

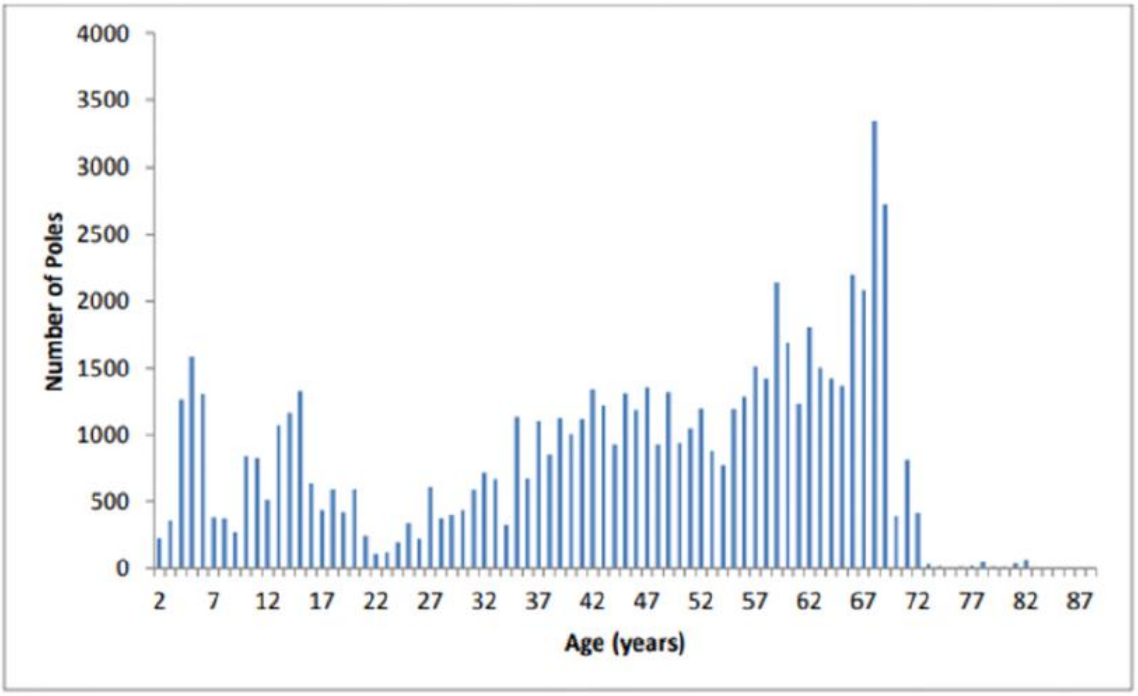
81. The following Figure demonstrates the nexus between pole age demographics and poor condition or failure rate:[67]

[65] Exhibit I, Tab 29, Schedule PWU-13, Page 1 of 1

[66] This was precisely the reason why Hydro One management originally rejected Plan-B in favour of Plan-A. Of course, the negative effects associated with Plan-B are increased under Plan-B Modified.

[67] Undertaking J 7.3, Figure 2

Figure 2: Demographics of Poles that are in Poor Condition



82. As can be seen from Figure 2, more and more poles need replacement with an increase in age. Another way of looking at the link between condition and age of poles is that the average age of Hydro One's total population of poles is 38 years whereas the average age of its poles in poor condition is 45 years.[68]

83. The link between age and failure rate was further confirmed by Hydro One's witness during cross-examination:[69]

> **MR. STEPHENSON: All right. And I'm going to suggest to you that directionally it is probable that the number of poles that are newly in poor condition each year is going to be trending upward. You'd agree with me about that?**
>
> **MS. GARZOUZI: I think due to the aging demographic it's reasonable to assume that the trend will slightly increase.**
>
> **MR. STEPHENSON: And there is a strong correlation between your demographics and pole condition, correct?**

[68] Hearing Transcript, Volume 7, June 21, 2018, Page 155, lines 14-18
[69] Hearing Transcript, Volume 7, June 21, 2018, Page 154, lines 9-21

MS. GARZOUZI: Yeah, so the expected service life is the population view and the failure rate analysis on that population, so there is a correlation between age and failure rate.

84. The second impact that makes pole age a significant factor is that more old poles means that more poles will fail and will need to be replaced on an unplanned basis, at a higher cost and reliability impact.

85. Board Staff's submission proposes a disallowance of $78 million to the pole replacement program for poles it contends could instead be refurbished.[70] This submission ignores the evidence of the Navigant witness who stated specifically that pole replacement is not a substitute for a pole replacement program, and that it would make no sense to refurbish a pole which is already 50 or 60 years old.[71] Ms. Garzouzi stated in oral hearing that an overwhelming majority of Hydro One's poles cannot be refurbished.[72] Poles cannot be refurbished if they have woodpecker damage, are in rock or swamps, are joint-use poles, are off-road, or are over 50 years old. After accounting for those poles that cannot be refurbished, only 10,000 of the poles that require action are potential candidates for refurbishment.

86. Navigant's benchmarking study shows that refurbishments cost approximately one-seventh of a pole replacement among Hydro One's peers, however, Hydro One currently does not refurbish poles. It is not clear what a refurbishment will ultimately cost and what implementation costs, such as new equipment and training costs, the utility will incur.

87. Furthermore, the 10,000 poles that are candidates for refurbishment have not been assessed to determine if refurbishment is the best option. The number of poles provided is simply the number of poles in which refurbishment is not specifically precluded. At this time there is no basis to determine either the number of refurbishments or cost of refurbishment. The PWU submits that there should not be a disallowance for pole replacements until a proper analysis of refurbishment feasibility is undertaken.

[70] OEB Staff Submission, Pages 78-79
[71] Hearing Transcript, Volume 6, June 19,2018, Page 13, lines 8-17
[72] Hearing Transcript, Volume 8, June 22,2018, Pages 28-29, lines 26-28 & 1-9

88. Citing Navigant's study, Board Staff suggested that Hydro One has poor performance in controlling pole replacement costs.[73] However, in the oral hearing the witness from Navigant, Mr. Grunfeld, stated that Hydro One was not statistically different from the mean of the comparison group during the study period.[74] The PWU notes that pole replacement costs per unit have decreased since the end of the 2012 to 2014 study period.[75]

89. To sum up, pole age demography should be a key input in projecting wood pole replacement requirements; the proposed pole replacement program under Plan B-Modified is not indicative of that. The PWU submits that an increased pace in pole replacement is needed to address premature decay and mitigate the risk of approaching a new wave of poles reaching ESL and the rate of replacement should not be based on forecast reliability impacts alone.

ii. Managing Pole Failures

90. Poles in poor condition have a higher probability of failure than poles in good condition. Hydro One's evidence shows that outages due to pole failures average 345 annually, and each outage impacts an average of 185 customers for 10 hours. In total, pole failures contribute approximately 3% to SAIDI and 2% to SAIFI. In addition, pole failures generally occur in the public domain and therefore represent a public health and safety risk.[76]

91. Hydro One manages a population of 1.6 million poles. Inspections show that of these 67,000 are in poor condition and 39,000 are in the Red Pine pole set that need to be addressed due to premature failure. In other words, currently 106,000 poles require replacement.[77] In response to a PWU interrogatory, Hydro One stated that by the end of 2022, an additional 67,000 poles (13,400 poles per year) are forecasted to be added to this high risk category due to deteriorating condition.[78] Adding these 67,000 additional

[73] OEB Staff Submission, Page 65
[74] Hearing Transcript, Volume 5, June 18, 2018, Page 136, lines 15-17
[75] Exhibit B1-1-1, DSP Section 1.4, Page 3 of 43
[76] Exhibit B1-1-1, DSP Section 2.4, Page 3 of 8
[77] Ibid.
[78] Exhibit I, Tab 29, Schedule PWU-14, Page 1 of 2

poles in poor condition to the 106,000 poles that are currently in poor condition will result in 173,000 poles. As indicated earlier, Hydro One proposes to replace 72,150 poles over the plan period, which means the number of poles in poor condition at the end of 2022 will be close to 101,000.

92. The proposed pole replacement program is therefore expected to slightly reduce the number of poles currently in poor condition – 106,000 to 101,000 - a reduction by about 5000.

93. Neither Hydro One nor the Board should be satisfied with this forecast. Hydro One's forecast of 67,000 poles to be added to the poor condition cohort over the next 5 years is based on historical numbers and ignores the impact of the ever increasing share of Hydro One's poles exceeding ESL. With the increase in the number of poles beyond ESL, Hydro One should expect an increase in the number of pole failures beyond the 2018-2022 test period. This was pointed out during the hearing by Counsel for the PWU:[79]

> **MR. STEPHENSON: All right. And I'm going to suggest to you that directionally it is probable that the number of poles that are newly in poor condition each year is going to be trending upward. You'd agree with me about that?**
>
> **MS. GARZOUZI: I think due to the aging demographic it's reasonable to assume that the trend will slightly increase.**

94. In AMPCO-23, Hydro One provided data which shows that the share of poles in poor condition for the period 2013-2017 has stabilized at 4%; however, with the proposed pole replacement program -which is expected to reduce the number of poles in poor condition to 101,000, the share will increase to close to 6%.

95. The PWU also notes that in its last distribution rate case (EB-2013-0416 - 2015-2017 rates application), Hydro One reported that about 50,000 poles had failed the hammer test. This number has increased in the past three years to 67,000.

96. The indisputable fact is, therefore, the proposed pole replacement program under Plan B-Modified does nothing to reverse the increasing trend in the share of poles in poor condition or reduce Hydro One's backlog of poles that need replacement. In fact,

[79] Hearing Transcript, Volume 7, June 21, 2018, Page 154, lines 9-15.

neither Plan A nor Plan B would have addressed the problem in any meaningful way. Hydro One's evidence shows that Plan A and Plan B would have reduced the number of poles needing replacement from the current 106,000 to only 93,000 and 96,000, respectively, by the end of the planning period (2022).[80]

97. Hydro One makes the point that the poles it places into its pole replacement program are those which fail a test, not those with bad demographics. The PWU accepts this proposition. However, the PWU notes the following:

a. Hydro One's pole replacement rate affects the pace at which poles which have failed tests are replaced. Currently, a pole which has failed a test may not be replaced for up to 5 years. During that period it remains in-service but with a heightened risk of unplanned failure;[81]

b. Hydro One's submission suggests that the proposed replacement rate is the appropriate one from the perspective of system integrity and sustainability. It is not. The Board has the benefit of Hydro One's own judgment on this question. When Hydro One examined that question, its conclusion was "Plan-A", which called for the replacement of 6000 additional poles over the rate period. Plan B-Modified was selected, not because it represented the optimal asset management plan, but rather because it was perceived to have more acceptable rate impacts;

c. In a perfect world, poles would be replaced on a "just-in-time" basis, the day immediately prior to the day the pole would otherwise fail. Of course, this does not represent the real world. The fact that a pole is replaced prior to failure does not reflect imprudence – to the contrary, it is an intrinsic element of a prudent asset management program. Current ratepayers are paying the price for historic underinvestment – through deteriorating reliability performance and deteriorating asset demographics.

[80] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.4, Page 3 of 8

[81] Unplanned failures result in service interruptions (adversely affecting customers and reliability statistics) and higher costs for the replacement.

This historical mistake is being repeated – and compounded – leaving future ratepayers with a "bow-wave" of replacement backlogs;[82] and

d. In recent years, the Board has increasingly used benchmarking results on a prescriptive basis – directly impacting Hydro One's revenue requirement. In this case, the Board has benchmarking evidence revealing that Hydro One's peers have much more pro-active pole replacement programs, resulting in significantly superior demographic profile for their pole portfolios. The Board should be guided by these benchmarking results.

98. On the basis of this evidence, the PWU submits that Hydro One should be replacing poles on a more aggressive timetable, and that a more aggressive timetable is easily justifiable as reasonable. The PWU submits that Hydro One's proposal under Plan A represents the absolute minimum that can be considered to be acceptable without (a) further jeopardizing system reliability; and (b) inappropriately shifting costs to future ratepayers.

b. Asset Management: Station Refurbishment

99. Hydro One operates 1,005 stations, of which 70 are in poor condition. Plan A proposed to replace all stations deemed to be in poor condition (70) by the end of the planning period (2022). SAIDI and SAIFI were forecast to improve by 14%.[83] Plan B proposed to reduce the number of stations in poor condition to 40 by the end of the period. SAIDI and SAIFI were forecast to improve by 5% as a result.[84] Plan B-Modified proposed a scenario that would maintain the number of stations in poor condition at 70 by the end of the period. SAIDI and SAIFI were forecast to change by 0% as a result of this factor.[85]

[82] Ironically, ratepayers are likely to be facing these additional costs at a time when they no longer have the protections of the FHP.
[83] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.4, Page 4 of 8
[84] Ibid.
[85] Ibid.

100. The following chart demonstrates the impact each investment plan would have on Hydro One's station condition at the end of the plan (2022).[86]

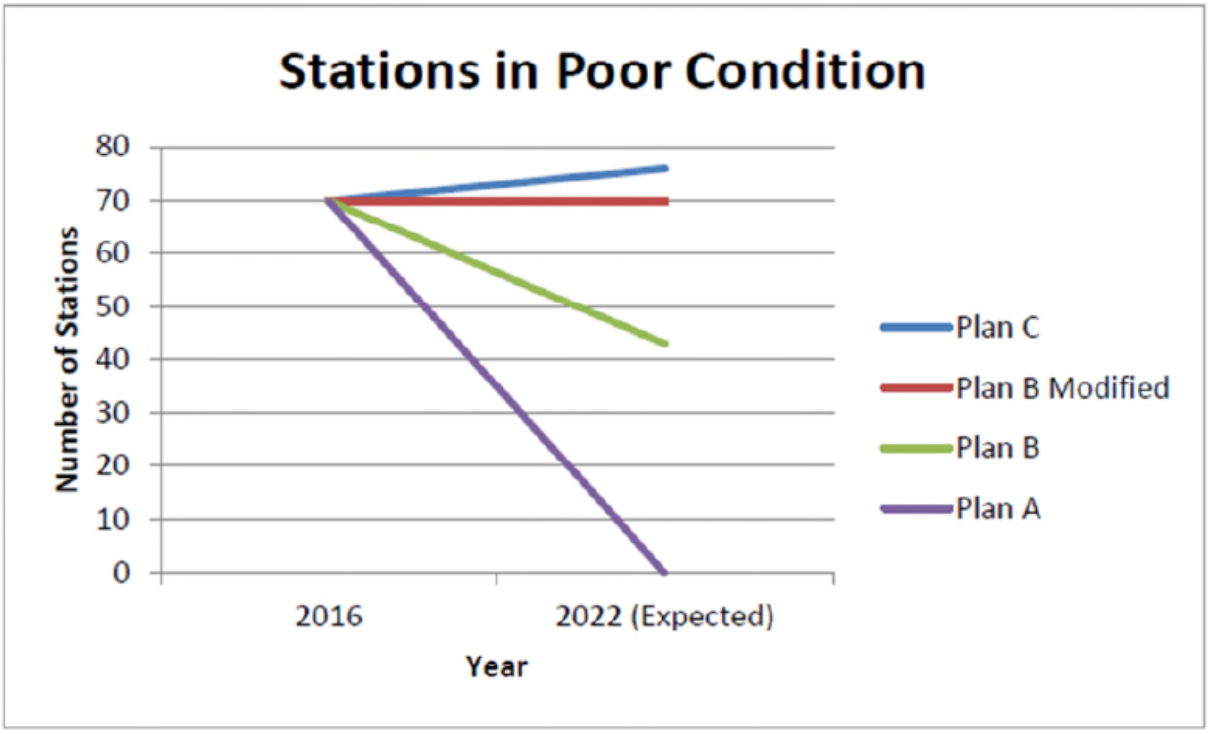


Figure 2: Impacts of Plan Alternatives on Distribution Station Population

101. Under the selected Plan B-Modified option, Hydro One is proposing to invest $148.1 million[87] on its Distribution Station Refurbishment program over the test period to refurbish 73[88] stations.

102. Hydro One notes that distribution station transformer failures are highly impactful. While the total number of failures varies from year to year, the number of major transformer failures (Class 1) and number of potential major failures avoided by proactively removing transformers from service (Class 2) are shown in Figure 18. It can be seen that total failures have gone down on the system since 2013.[89]

[86] I-35-BOMA-31, Figure 2
[87] Exhibit B1, Tab 1, Schedule 1- ISD SR-06
[88] Exhibit I, Tab 24, Schedule AMPCO-6 (h)
[89] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Page 12 of 89

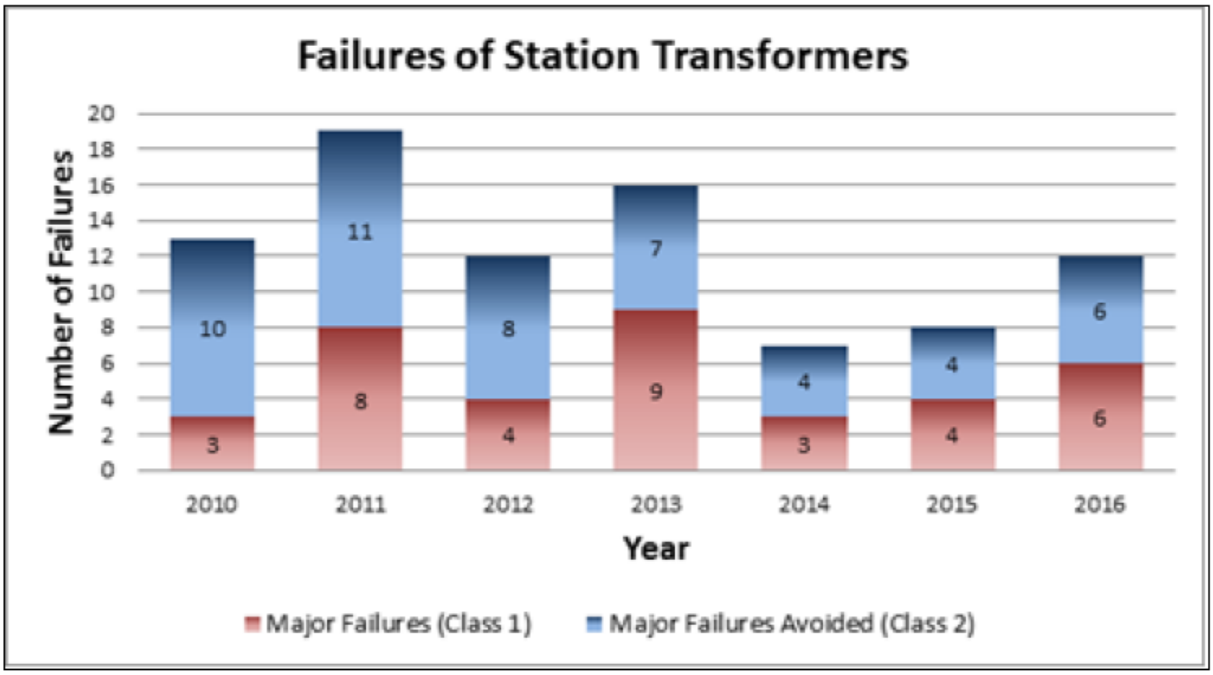


Figure 18 - Failures of Station Transformers

103. Hydro One explains that the reason for the decrease in failures in years 2014 and 2015 is the result of an increase in planned replacements of transformers in poor condition.[90] As can be observed from Figure 19,[91] which represents the number of planned and unplanned station transformer replacements from 2010 to 2016, the steady increase in total transformer replacements from 2011 to 2015 corresponds with an overall decrease in transformer failures over the same period.

[90] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Page 12 of 89
[91] Ibid.

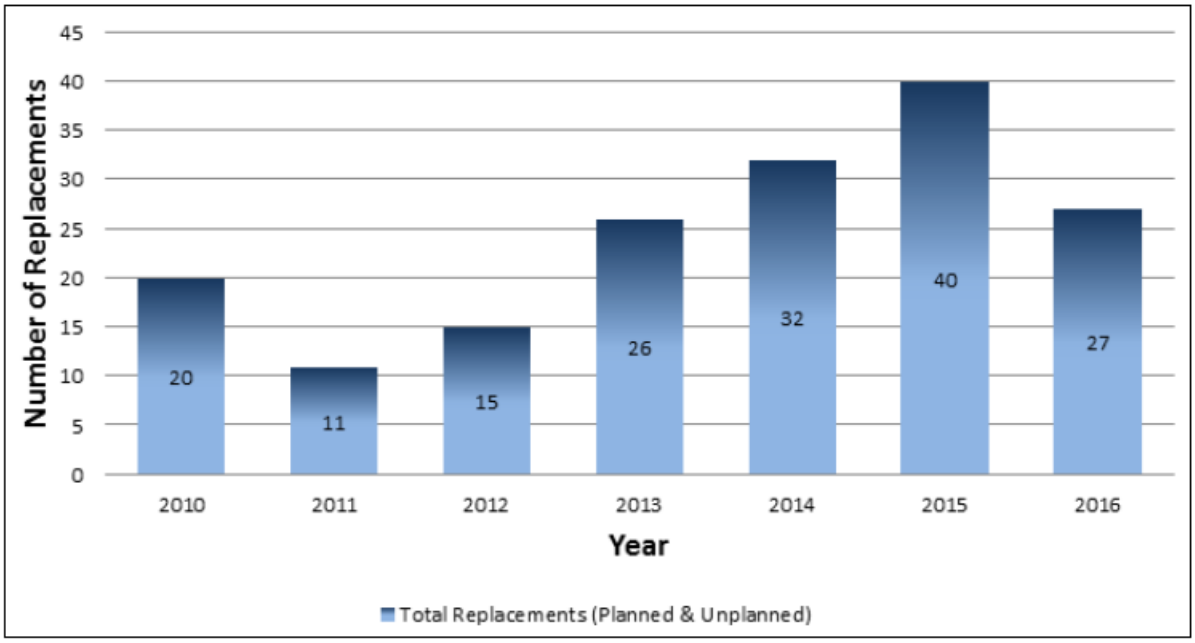


Figure 19 - Number of Transformer Replacements

104. The correlation between a steady increase in station transformer replacement and a decrease in transformer failure is therefore clear.

105. As indicated earlier, Hydro One is planning to refurbish 73 stations that are in poor condition over the next 5 years and maintain the current level of stations in poor condition (70) by the end of the plan period. Expressed in terms of station transformers, the plan is to replace 75 station transformers (because two of the stations to be replaced have two transformers each) over the next 5 years.[92]

106. Currently, 23% of Hydro One's distribution station transformers (280 transformers out of a total of over 1200 transformers) are classified as high risk based on condition assessment.[93] Hydro One states that these transformers are at a higher risk of failure:

> **Based on results gathered, approximately 23% of distribution station transformer condition assessments fall into the high risk category. Figure 16 illustrates which component of the transformer is the main contributing factor to the condition of the 280 high risk distribution station transformers. These units are at a higher risk of failure compared to the transformer population and should be considered for replacement, refurbishment or other remedial action in order**

[92] Exhibit B1, Tab 1, Schedule 1, ISD: SR-06, Pages 3-5 of 7
[93] Exhibit B1, Tab 1, Schedule 1, ISD: SR-06, Page 1 of 7, lines 15-17

> **to correct significant deterioration or deficiencies. This is required to prevent failures and reduce impacts to Hydro One's distribution customers.[94]**

107. The evidence also shows that the proposed station (transformer) refurbishment plan is expected to maintain the current level of transformers in poor condition at 23% by the end of the pan period.

> **The proposed plan is to refurbish an average of 15 distribution stations per year over the 5 year period, as noted in the table below. This is expected to maintain the current level of transformers in poor condition at 23% (even though the overall age of the fleet will increase) with the goal of maintaining the current level of station reliability in line with customers' preference to balance reliability and rate impacts.[95]**

108. Based on this evidence, Hydro One currently has 280 (23%) transformers in poor condition (High Risk) and plans to replace 75 transformers over the plan. At the end of the 5-year period there will still be 280 transformers in poor condition. It can be concluded therefore that Hydro One is forecasting an additional 75 transformers to be newly added to its cohort of transformers in poor condition over the next 5 years. Moreover, the reason why Hydro One selected a plan that would keep the same number of transformers in poor condition at the end of the plan is rate/bill impact.

109. The PWU submits that there are two fundamental problems with Hydro One's plan. First, the refurbishment or replacement of only 75 transformers in the next 5 years is far short of what is needed to deal with the backlog of 280 transformers that are categorized as high risk. At the proposed rate of replacement/refurbishment, it would take Hydro One another four rate periods to clear the backlog, without even considering transformers that will be newly added to the 'poor condition' category. The consequence of such a plan is that an increasing number of these transformers will fail completely and Hydro One will be forced to undertake a large number of unplanned replacements/refurbishments at a higher cost and reliability impact.

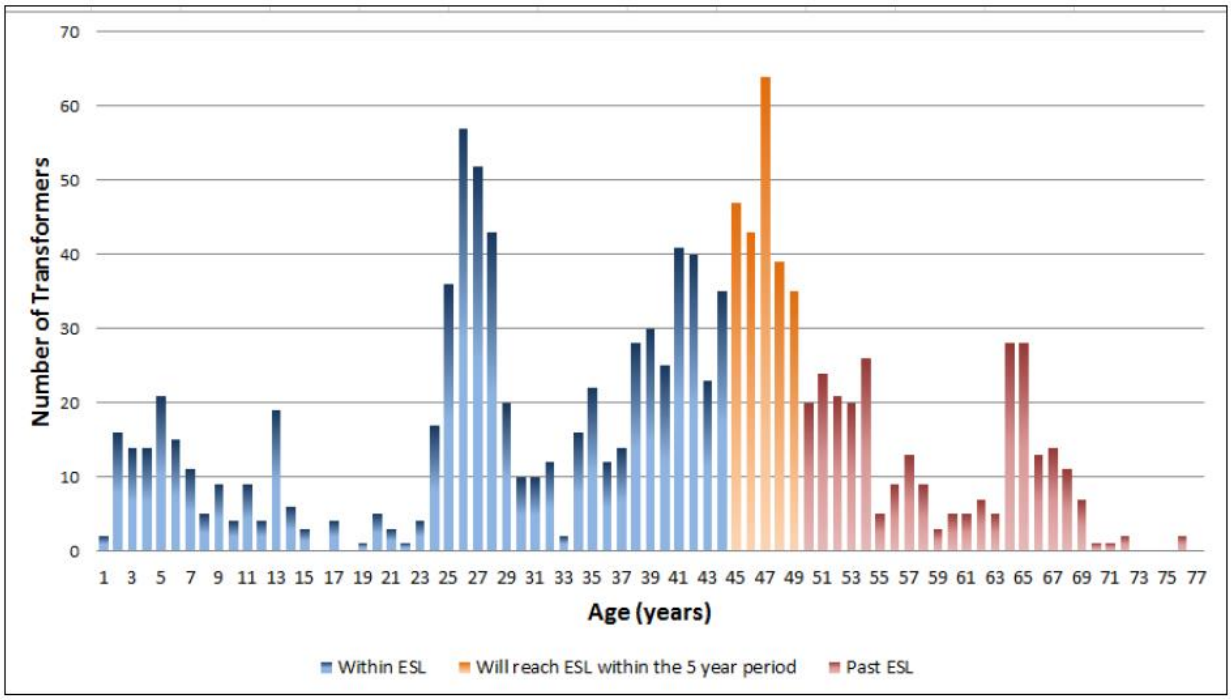
110. Secondly, Hydro One's transformers are one of the oldest among the peer group and are increasingly getting older. Hydro One's evidence indicates that it utilizes an ESL of 50 years for its distribution station transformers. Only two utilities considered by Navigant have a higher ESL than Hydro One's whereas the remaining utilities have an

[94] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Page 10 of 89
[95] ISD: SR-06, Page 3 of 7, lines 2-3

ESL of 40 years or lower.[96] Currently 23% of the transformer population is beyond its ESL, with an additional 19% to reach its ESL in the next five years.[97]

> **Currently 23% of the transformer population is beyond its expected service life, with an additional 19% to reach its expected service life in the next five years. While not all of these transformers require immediate replacement, the long-term management of the high number of transformers reaching expected service life requires increased capital investment. A sustained program targeting a high number of transformer replacements is required to maintain the historical number of transformer failures at a manageable level for customers.**

Figure 17 - Demographics of the Distribution Station Transformers[98]



111. In this regard, Hydro One's forecast of 75 transformers to be added to the poor condition cohort over the next 5 years is based on historical numbers and ignores the impact of the ever increasing share of transformers exceeding ESL. With the increase in the number of transformers beyond ESL, Hydro One should expect an increase in the number of transformers in poor condition.

112. The PWU submits that the station/transformer replacement or refurbishment plan proposed under Plan A is more appropriate.

[96] Navigant Benchmarking Study, Section 4.2.2, page 22
[97] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.3, Page 11 of 89
[98] Ibid.

c. Vegetation Management

113. Hydro One is proposing a significant change to its vegetation management program. Until recently, the program was designed to clear right-of-way corridors on an 8 year cycle[99] but historically corridors were cleared on an average cycle of 9.5 years.[100] As a result there is a backlog in vegetation management that must be dealt with in the test period to mitigate impacts on reliability.

114. Hydro One retained CN Utilities to produce a study and provide recommendations to improve their program that was filed with the original application. This October 2016 study was an update to a study originally produced in 2009. Pursuant to CN Utilities' recommendations, Hydro One forecast to increase their planned cycle clearing to 8,500 km per year and tactical maintenance to 4,250 km per year.[101] A significant portion of the increase in sustainment OM&A, a $7 million increase, is attributable to increasing the work program to address the current backlog.[102]

115. Since filing this application in March 2017, Hydro One changed its vegetation management strategy as outlined in Exhibit Q filed in December 2017. The company worked with Clear Path Utility Solutions ("Clear Path") to develop a new approach that significantly changes its vegetation management strategy. The Clear Path strategy moves the cycle clearing program from an eight year cycle to a three year cycle. This plan requires 34,666 km of right-of-way corridor to be cleared annually.[103] This program focuses on addressing defects, vegetation most likely to cause an interruption, rather than clearing all vegetation within a corridor.

116. Hydro One forecasts no change to its vegetation management costs, and therefore no corresponding change to the requested revenue requirement, resulting from this change though they suggest there could be decreased costs after the 2018-

[99] Exhibit Q, Tab 1, Schedule 1, Page 12 of 25
[100] Exhibit B1, Tab 1, Schedule 1, DSP Section 1.6, Attachment 2, Page 2
[101] Exhibit C1, Tab 1, Schedule 2, Pages 31-32 of 33
[102] Exhibit C1, Tab 1, Schedule 1, Page 6 of 8
[103] Exhibit Q, Tab 1, Schedule 1, Page 13 of 25

2022 test period.[104] As this new program is untested in this jurisdiction and in the early stages of implementation it is not yet clear whether the significant changes will be feasible for a utility with over 100,000 km of right-of-way corridor such as Hydro One. Mr. Tankersley of Clear Path confirmed in the oral hearing that Hydro One has not met its early milestones.[105]

117. In the following exchange with the PWU, Mr. Tankersley described the conditions for which he believes the proposed vegetation management program should be evaluated.[106]

> **MR. STEPHENSON: Okay, and then just finishing up with this, sir: What should this Board be looking for in order to give it confidence that this program is succeeding, you know, in the sense of--or putting it the other way, what red flags should the Board be looking for if it's--if this program is in trouble and not--not not being deployed as you had hoped or not achieving the results that you had hoped or whatever. So at what point in time is it fair for the Board to say, you know, things are okay, they're all looking great, or--and--or there is some concern here? Is it after a year? So when is it, and what is it they should be looking for?**
>
> **MR. TANKERSLEY: You will start to see the results after the first year. In fact, you may start to see some of those results before that. After the first three-year cycle it will become very apparent, and as you start the second cycle, but there are two elements that you might look at. We talked a little bit about quality control. There is another element that I would characterize as quality assurance. Now, the whole pretext of this is that we are going to--it is going to be a defect-based system. So we are going to prevent defects. Defects, as a segment of the entire population, are relatively--should be relatively small, and what we're looking at right now, not so much.**
>
> **There is about 800,000 as we see. If you were to do a similar but not as exhaustive survey as we did in the last survey, where you were looking at defects at different times since the feeder was performed and then in aggregate and measure it against the information that we provided on a defect rate, you should see improvement after the first year. Now, overall I believe the number was defects per kilometre. That's across all feeders, irrespective of when they were last worked. After the first year I should see a number that is significantly different than that, and those feeders that were done more recently should have a zero or near-zero defect per kilometre basis. Now, that's showing one thing that you are addressing the defect levels on the system. The second component of that is we--just yesterday looked at--is outage investigation. These are disruptions caused by trees.**
>
> **Disruptions caused by trees can either be random, it is a green healthy tree during a storm, or any other event where it falls, or it's related a tree that has a defect, that I believe a defect is more--more likely to cause a disruption than a**

[104] Exhibit Q, Tab 1, Schedule 1, Page 14 of 25
[105] Hearing Transcript, Volume 6, June 19, 2018, Page 17, lines 13-16
[106] Hearing Transcript, Volume 6, June 19, 2018, Pages 23-26

non-defect.

So if I were to measure that over time and I looked at my outages, and if they were defect cause or non-defect cause, and actually, we are starting to see that right now, and that those feeders that have the OCP applied have had very few, if any, outages caused by a defect. They have had outages, but those outages have been determined to not be caused by something that would have been under the scope of the work. Those feeders that have not been worked have a much higher rate of outages caused by a defect, and I think those two components together, over a period of time, will be able to tell you if your program is effective. Now, quality assurance point of it is--needs to come in at some point in the future, perhaps after the first year of the first cycle. It is a little too early for that, but you use the same or very similar processes we did in the survey, and then you can equate post and--pre and post results from a defect level.

MR. STEPHENSON: And, sir, are you advising Hydro One with respect to the metrics that they should be tracking in order to determine success or failure of this program as it's rolling out?

MR. TANKERSLEY: I have made some suggestions and have reviewed some of that, but not to any major extent.

MR. STEPHENSON: But I take it that some of those metrics would be what you've just talked about, these defects per kilometre and that sort of thing.

MR. TANKERSLEY: I believe that's the plan.

Mr. Tankersley went on to clarify that a defect is generally characterized as a tree coming into contact with a conductor through growth or by falling onto the conductor.

118. The PWU submits that the Board should approach Hydro One's new vegetation management plan with caution. While the concept bears promise, the execution will be the key. Caution is required for at least two reasons: first, the program is a radical departure from Hydro One's traditional approach, and untested in this jurisdiction. Second, the consequences to system reliability in the event the program goes awry or is unsuccessful are very significant. As a consequence, the Board should require Hydro One to provide updates with respect to its new vegetation management program to ensure the program is performing as designed and is demonstrably superior to the program that has been in place prior to 2018. The success of the new program should be evaluated on the basis of the kilometres of right-of-way corridor cleared, number of trees cleared or pruned, the impact of the program on reliability metrics, and the annual cost.

119. There are approximately 15,530 outages per year caused by tree contact.[107] The outages contribute 27% to SAIDI and 16% to SAIFI. The original vegetation management plan's focus on high-risk rights-of-way expected to bring vegetation-related impacts on SAIDI and SAIFI to 18% and 7%, respectively, though the expected reliability impacts are less clear under the new program.

120. Vegetation-related outages are the single largest contribution to SAIDI.[108] The PWU submits that reliability impacts of the vegetation management program should be evaluated independently from the reliability impacts related to Hydro One's capital assets. Reliability impacts of assets are dependent on asset condition. The vegetation management program does not impact the condition of distribution assets and program spending in this area cannot act as a substitute for capital investments.

121. Board Staff's submission suggests that potential reliability improvements in the area of vegetation management could offset the requirement for reliability improvements in other areas. The submission cites Clear Path's study that proposed reliability could be improved by 20% to 40% by the end of 2020 by implementing an optimal maintenance cycle, modified work scope and an analytics-based hazard tree program.[109] This level of improvement, however, requires "funding beyond the baseline maintenance levels".[110] As this program is new it is not clear that the proposed benefits will be realized.

122. Consistent with Hydro One's application, Board Staff's submission places too much emphasis on the relationship between capital assets and reliability at the expense of asset conditions and demographics. Displacing resources needed for capital assets because of an apparent lower cost to achieve reliability improvements through vegetation management suggests it is appropriate to degrade one aspect of the distribution system to minimize costs in the short run. Hydro One's capital assets continue to degrade in both condition and demographics and this issue simply cannot be addressed by improvements elsewhere in the distribution system. The PWU submits

[107] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.4, Page 5 of 8
[108] Exhibit B1, Tab 1, Schedule 1, DSP Section 2.4, Page 6 of 8
[109] Exhibit Q1, Tab 1, Schedule 1, Page 4
[110] Ibid.

that it would be short-sighted to allow capital assets to continue to degrade due to the uncertain prospect of reliability improvements from the new vegetation management program.

V. Conclusion

123. Hydro One's number one concern in finalizing its DSP has been the cost and resulting rate impact at the expense of any serious consideration of the distribution system's long-term condition. This narrow focus has been shared by Board Staff and other intervenors throughout the application rate-setting process. This section of the submission has outlined the present need for capital investments for Hydro One's distribution system.

124. Hydro One submits that it has selected the capital investment plan that allows for the lowest possible capital spending and the lowest possible rate impact while maintaining the condition of its assets. Hydro One adds that another investment pacing feature of Plan B-Modified is that it reduces capital expenditures below a sustainable threshold for one year, 2018, to reduce the rate impact during that year and thereby ameliorating the impact caused by reductions in forecast load.[111]

125. The concern for minimizing rate impacts is certainly a valid one, but it is also short-sighted given Hydro One's aging and deteriorating asset populations. The PWU submits that the investment plan should be based on the need to deal with Hydro One's aging assets. Historical spend and short-term reliability impacts do not appropriately consider deteriorating asset conditions. The issue of assets increasingly falling into poor condition and large shares of assets reaching their end of service life is not going away. Unless material investments are made in this rate term, the problem can only become worse by Hydro One's next distribution rate application. As noted above, the reluctance of today's customers to accept rate increases is no justification for shifting costs to future ratepayers in circumstances where there is no reason to believe (and no evidence) that future ratepayers will be any more receptive to rate increases.

[111] Argument-In-Chief, Page 95

126. For the current rate period, however, the situation has materially changed since the implementation of the FHP. The majority of Hydro One customers will not face rate increases regardless of the outcome of this proceeding. The basis for the creation of the Plan B-Modified investment plan is no longer valid as rates have changed considerably for residential and small business customers.

127. The investment plan that was recommended by Hydro One's management, Plan A, allows for an appropriate pacing of replacements. Plan A will improve reliability in the short run, but more importantly it would provide a solid foundation for pacing investments beyond this rate period. The Plan B-Modified plan as proposed in this application will lead to more significant rate increases in the years after 2022.

128. Board Staff have proposed an 11% reduction to Hydro One's capital program based on a 17% reduction to its system renewal program and vague reductions to the remaining capital programs.[112] The PWU submits that Plan B-Modified is already insufficient and any additional reductions to capital spending would lead to unacceptable reliability impacts in both the short-term and long-term.

129. Board Staff cite relatively stable SAIDI and SAIFI figures in proposing that historical spending has been adequate.[113] SAIDI and SAIFI are lagging indicators that cannot be evaluated on the basis of spending within the same period. Moreover, the level of historical spending has led to an increasing amount of assets in poor condition and nearing their end of service lives. As Hydro One's assets continue to age and deteriorate they become more likely to fail. It cannot be expected that the utility's reliability indicators will remain stable in the future with this insufficient level of investment.

130. It is not a question of if Hydro One's aging assets will need to be replaced but when. The proposed Plan B-Modified level of investment does nothing but "kicks the can down the road" for future generations to deal with. Submissions made by Board Staff, and likely other intervenors, may suggest reductions in capital program spending for the sake of minimizing rate impacts but a deferred investment is not an avoided

[112] OEB Staff Submission, Page 4
[113] OEB Staff Submission, Page 83

investment. An application that ignores the issue of intergenerational equity cannot result in just and reasonable rates in the future and rates leading to this outcome should not be considered just and reasonable today.

131. The PWU submits that the level of capital investment required for Plan A, as recommended by Hydro One management, should be approved for this rate period. The reasons for management's original recommendation of Investment Plan A are still valid but the reasons for proposing Plan B-Modified, i.e. bill impacts, are no longer relevant for the majority of customers due to the FHP. There will simply never be a better time for Hydro One to make the capital investments reflected in Plan A.

F. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

Issue 38: Are the proposed OM&A spending levels for Sustainment, Development, Operations, Customer Care, Common Corporate and Property Taxes and Rights Payments, appropriate, including consideration of factors considered in the Distribution System Plan?

Issue 39: Do the proposed OM&A expenditures include the consideration of factors such as system reliability, service quality, asset condition, cost benchmarking, bill impact and customer preferences?

132. Hydro One has made significant progress in mitigating rate increases by reducing its operations, maintenance, and administration costs recovered within the revenue requirement. The level of OM&A sought in this application is lower than the amounts approved for 2016 and 2017 and a significant decrease from the amount recovered in 2014. OM&A spending since 2014 is summarized in the chart below.[114]

[114] Exhibit C1, Tab 1, Schedule 1, Page 2 of 8

Table 1: Summary of Recoverable OM&A Expenses ($ Millions)

Description	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
Sustainment	325.7	304.6	316.5	323.7	361.4	334.5	367.1	346.7
Development	11.0	10.9	15.4	11.9	17.8	13.2	17.0	11.0
Operations	29.5	27.6	35.8	31.5	39.4	33.4	37.5	36.7
Customer Care	209.3	155.4	111.7	118.8	110.9	132.6	111.6	131.6
Common Corporate Costs and Other	94.4	69.1	59.0	72.0	54.8	54.4	54.7	53.9
Property Taxes & Rights Payments	4.6	4.8	4.7	4.6	4.9	4.7	5.0	4.9
Total	**674.5**	**572.5**	**543.1**	**562.6**	**589.1**	**572.8**	**593.0**	**584.8**
% Change (year-over-year)		*-15.1%*	*-19.5%*	*-1.7%*	*8.5%*	*1.8%*	*0.7%*	*2.1%*
% Change (Test vs. 2016 Actual)								*3.9%*

"Approved" figures reflect OEB-directed reductions to Sustainment OM&A and Common Corporate Costs and Other OM&A line items (specifically, budgets for vegetation management, LEAP funding, and compensation).

133. Hydro One has been able to control its OM&A despite an ongoing increase in customer count. The following table, prepared by the PWU, outlines OM&A trends in the context of OM&A per customer.[115]

	Historic					Bridge		Test
	2014 IRM	2015		2016		2017		2018
	Actual	Actual	Approved	Actual	Approved	Forecast	Approved	Forecast
OM&A ($000)	674,500	572,500	543,100	562,600	589,100	572,800	593,000	584,800
Customers (000)	1,267	1,274		1,283		1,292		1,301
OM&A / Customer ($)	532.29	449.24	426.17	438.38	459.03	443.36	458.99	449.67

134. Forecast OM&A per customer increases by only 1.4% from 2017 to 2018. There is a significant drop from 2014 to 2018 as OM&A per customer has declined by 15.5% over this period. By the design of the I-X formula, OM&A will continue to grow by a rate lower than inflation through the test period. OM&A per customer will decline by an even greater degree over this period as the customer count continues to grow.

[115] Exhibit C1, Tab 1, Schedule 1, Page 2 of 8 & Exhibit E1, Tab 2, Schedule 1, Page 39 of 42

135. OM&A reductions are largely the result of material productivity savings forecast through the rate period. OM&A savings are forecast to grow from $29.4 million in 2018 to $45.5 million by 2022.[116] These savings *are* embedded within the application and not a part of the productivity savings to be achieved within the 0.45% stretch factor.

136. By reducing the level of OM&A sought within the application, Hydro One is acting to reduce revenues associated with productivity savings while shifting the risk of achieving the savings from the ratepayer to the shareholder. Productivity savings are forecast to be achieved through a number of work programs. In particular, OM&A savings will be achieved through lower negotiated contracts with information technology providers, cable locate outsourcing, increased eBilling, and reduced expected trouble calls.[117]

Issue 40: Are the proposed 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate (excluding executive compensation)?

Issue 41: Has Hydro One demonstrated improvements in presenting its compensation costs and showing efficiency and value for dollar associated with its compensation costs (excluding executive compensation)?

137. Both total compensation and complement are declining through the test period.

138. Since Hydro One's last custom distribution rate application for 2015-2017 rates (EB-2013-0416) the company has negotiated two collective agreements with the PWU and the Society. The outcomes of the 2015 collective agreements demonstrated significant progress in Hydro One's efforts to control compensation costs. Hydro One's director of human resources, Mr. McDonell, discussed some of these outcomes in cross-examination with PWU counsel:[118]

> **MR. STEPHENSON: Let me just come back for a moment. Not in the most current round of bargaining, but in the one prior to that -- we had a discussion about this before. This was the bargaining that was done more or less at the same time as the initial discussions about the IPO. There was a pretty significant deal made with both my client and in fact with the Society in terms of**

[116] Exhibit I, Tab 25, Schedule Staff-123, Page 2 of 3
[117] Ibid.
[118] Hearing Transcript, Volume 3, June 14, 2018, Pages 20-22

restructuring some aspects of that collective agreement, correct?

MR. McDONELL: Yes. If I could expand upon that a little bit, what we are referring to is the last round of bargaining that happened in 2015 resulting in a three-year collective agreement that just expired. In the evidence, we refer to that as a paradigm shift in our negotiations with, quite frankly, the PWU and the Society.

What I mean by that is that we were able to achieve things that we have never been able to achieve before, namely a lower-than-average base wage increase and lump sums. Traditionally, unions aren't totally in favour of lump sums because it doesn't get put into the base rate.

But by being creative and with the assistance of the government, we were able to come up with up with an agreement that did results in that, and in return, which is also an advantage for Hydro One as well, the PWU and the Society members were able to enjoy share grants in the IPO of Hydro One.

MR. STEPHENSON: That collective agreement has now come to an end. What if any continuing benefits for the period of time encompassed by this application does that deal have? Is that all now done, or is that just a historical issue, or is there some continued significance to that in terms of cost control for the period of this application?

MR. McDONELL: One thing that comes to mind is there a residual impact, if you will, on having a lower base-rate increase in that other compensation items, such as overtime, the pension formula, a variety of different allowances that PWU members are entitled to, quite often are based upon the base rate. By having a lower base rate negotiated, there is a multiplier effect in the future for those particular costs.

139. The base rate increases on the wages of PWU represented employees was 1% in each year from 2015 to 2017 and Society wages increased 2.25% in 2015 followed by three years of 0.5% increases.[119] The lower than inflation base-rate wage increases coming out of the 2015-2017 collective agreements allow for a lower starting point for which compensation is based within this application.

140. The rate of base salary increases embedded in the application maintains the low annual increases negotiated in the 2015 collective agreements. The annual base salary increases are 1% for PWU represented employees from 2018 to 2022 and 0.5% for Society represented employees.[120] These lower-than-inflation wage increases demonstrate Hydro One's commitment to control compensation costs.

[119] Exhibit C1, Tab 2, Schedule 1, Page 29 of 51
[120] Exhibit C1, Tab 2, Schedule 1, Page 33 of 51

141. On July 11, 2018 Hydro One filed a Memorandum of Agreement with the PWU in respect of its 2018 to 2020 collective agreement. The memorandum shows wage increases of 1.8% in April 2018, 2.0% in April 2019 and 0.6% in January 2020.[121] As the memorandum notes, the revenue requirement sought in this application has not been adjusted to reflect these higher rates.

142. In the oral hearing, Mr. McDonnell confirmed that any increases above the 1% escalation embedded in the application will be borne by shareholders and not ratepayers.[122] The incremental $8.3 million[123] that would be subject to recovery from ratepayers had Hydro One sought to increase its revenue requirement is akin to a disallowance that has already been accepted by Hydro One. By maintaining its current revenue requirement, Hydro One is committing to recover through rates at least 8 years (2015-2022) of lower-than-inflation wage rate increases.

143. The PWU submits that, from the Board's perspective, the critical issue with respect to compensation should be overall compensation cost, rather than wage rates, or the cost of individual elements of employee compensation. Hydro One's holistic strategy with regard to compensation costs should be evaluated based upon its ability to reduce total compensation dollars. The base wage rate and total compensation per employee do contribute to the level of total compensation. However, they are not the only factors, and consideration of these measures should be made within the context of Hydro One's overall strategy.

144. Hydro One's commitment to maintaining appropriate compensation costs is best demonstrated by looking to the actual compensation spending and an analysis of trends. Total compensation is declining by 0.62% through the test period.[124]

	2018	2019	2020	2021	2022
Total Capital Dx Comp	425,294,822	436,987,864	439,439,816	447,778,837	452,114,859
Total OM&A Dx Comp	208,736,617	201,840,710	187,934,461	164,357,645	166,218,310
Total Dx Compensation	**634,031,439**	**638,828,575**	**627,374,277**	**612,136,482**	**618,333,169**
% Increase		0.76%	-1.79%	-2.43%	1.01%

[121] Memorandum of Agreement with PWU and Variance Analysis – Filed July 11, 2018
[122] Hearing Transcript, Volume 3, June 14, 2018, Page 23, lines 8-21
[123] Memorandum of Agreement with PWU and Variance Analysis – Filed July 11, 2018, Page 2, Table 2
[124] Exhibit I, Tab 40, Schedule SEP-013, Attachment 1

145. By the end of the test period, the total level of compensation recovered through rates will be lower than total compensation in any year from 2014 to 2016. The decline in total compensation is the result of a decline in Hydro One's total complement and the lower-than inflation-increases in compensation per employee.

146. The total number of Hydro One distribution FTEs is forecast to decline each year from 2018 to 2022.[125]

	2018	**2019**	**2020**	**2021**	**2022**
Dx Unrepresented FTEs	359	356	344	330	330
Dx Society Represented FTEs	735	730	704	674	674
Dx PWU Represented FTEs	1,833	1,815	1,755	1,682	1,678
Dx Temporary FTE	1,246	1,202	1,195	1,188	1,189
Total FTEs	**4,173**	**4,103**	**3,998**	**3,874**	**3,871**
% Increase		-1.68%	-2.55%	-3.10%	-0.09%

147. Overall, the number of FTEs declines by 1.86% per year though the test period and PWU represented FTEs declines by 2.18% per year, a total of -7.42% and -8.69% respectively. FTE reductions are partially a result of productivity initiatives to reduce the number of back office support staff through the Move to Mobile program, which increases field productivity through geographic based auto-scheduling, engineering work team migration, and corporate common head-count reductions.[126]

148. The decline in complement, which is present for each represented group of employees, occurs despite a gradual increase in customer count within its current service territory through the test period in addition to the integration of the Acquired Utilities in 2021.[127]

[125] Exhibit I, Tab 40, Schedule SEP-013, Attachment 1
[126] Exhibit I, Tab 25, Schedule Staff-123, Page 2 of 3
[127] Exhibit E1, Tab 2, Schedule 1, Page 5 of 42

Table 3: Hydro One Distribution Load and Number of Customers

Year	GWh Delivery Forecast	Distribution Customer Count
2018	36,019	1,300,516
2019	35,680	1,309,216
2020	35,673	1,317,967
2021*	36,363	1,386,522
2022*	36,373	1,395,578

* The figures include the impact of integrating Acquired Utilities into Hydro One Distribution.

149. Compensation cost savings from a declining complement more than offsets the low increase in compensation per employee through the rate period. Compensation per employee increases by lower-than-inflation 1.26% per year through the test period.[128]

	2018	2019	2020	2021	2022	Average Annual Change
Unrepresented Comp/ FTE	256,357	261,014	266,039	271,189	276,920	
% Increase		1.8%	1.9%	1.9%	2.1%	1.95%
Society Comp / FTE	183,326	184,300	185,252	186,180	187,181	
% Increase		0.5%	0.5%	0.5%	0.5%	0.52%
PWU Comp / FTE	164,108	169,320	171,367	173,505	175,296	
% Increase		3.2%	1.2%	1.2%	1.0%	1.66%
Temporary Comp / FTE	85,383	86,588	87,561	88,584	89,648	
% Increase		1.4%	1.1%	1.2%	1.2%	1.23%
Total Compensation / FTE	**151,936**	**155,699**	**156,906**	**157,992**	**159,734**	
% Increase		**2.5%**	**0.8%**	**0.7%**	**1.1%**	1.26%

From 2014 to 2022, the average annual change in compensation per employee is only 0.2%.[129]

150. As 90% of Hydro One's workforce is unionized[130] the rigidity of the collective bargaining process plays a significant role in the company's overall compensation costs.

[128] Exhibit I, Tab 40, Schedule SEP-013, Attachment 1
[129] Ibid.
[130] Hearing Transcript, Volume 3, June 14, 2018, Page 14, lines 26-27

Mr. McDonell discussed the difficulties for Hydro One to minimize compensation increases given the ongoing unionized environment in cross-examination with the PWU:[131]

> **MR. STEPHENSON: And just as a general principle, at the end of the day, what happens is there is a trade-off as between various items; fair? That this isn't a one-item negotiation. Each side at the end of the day makes a deal based upon items that are of importance to it.**
>
> **MR. McDONELL: No, I agree with that. As a matter of fact, that is one thing that we tried to explain in our evidence, that collective bargaining in my view is different than a commercial contract. There is a relationship that existed and continues to exist in the future so that the parties are trying to find an agreement that both parties can ratify with their constituents.**
>
> **MR. STEPHENSON: Okay. One of the things we canvassed the last time around are what I would describe as -- you talked about a concept of rigidity in labour relations, whereby it is difficult in typical circumstances for an employer to extract absolute takebacks from a union, whether in terms of wages or pensions or whatnot. You are familiar with that concept?**
>
> **MR. McDONELL: I am familiar with the concept of rigidity, in the sense that it is difficult to negotiate clawbacks or rollbacks in terms of benefits or wages, unless, I suppose, unless there is what I would call a burning platform or an organization is in financial distress, and we see that, you know, in other forms where that has been achieved.**
>
> **But unless you do have that burning platform, it is very, very difficult, especially given our history of bargaining where we came from, from Ontario Hydro. It is very difficult to have rollbacks in wages and benefits.**

151. Mr. McDonell went on to discuss the negative outcomes that would arise with a potential work stoppage:[132]

> **MR. STEPHENSON: Just lastly on this point, I mean obviously one option which is available to either of the two sides involved in any negotiation is that there is a work stoppage, correct? That is at least a theoretical option that is available in any bargaining situation.**
>
> **MR. McDONELL: That is always an option and Hydro One, regardless of which union we are bargaining with, we always go into the process recognizing that can be an outcome and we do have a fairly robust contingency planning process to make sure that we have things in place in case there is a work stoppage.**
>
> **MR. STEPHENSON: Is it -- I think the answer to this question is self-evident. From the company's perspective, there are risks and costs implicit in a work stoppage. It is not -- you don't get that for free, from the company's perspective.**
>
> **MR. McDONELL: No, you don't. It is very harmful to the relationship.**

[131] Hearing Transcript, Volume 3, June 14, 2018, Pages 17-19
[132] Hearing Transcript, Volume 3, June 14, 2018, Pages 18-20

MR. STEPHENSON: It is problematic to your customers, as well.

MR. McDONELL: It is very problematic. I was just thinking about the last time we had a work stoppage with the PWU; you would have to go back to the 1980s. And in today's world, it would be very, very difficult for us to sustain a work stoppage for any length of time. We would be able to make work safe, but there definitely would be an impact on the parties, including the customer and the ratepayer, very soon after any work stoppage.

MR. STEPHENSON: Is it fair to say that when you are making a decision about what you can agree to at the end of the day in any particular agreement, you are weighing the costs and benefits of whatever that agreement might be relative to the alternative that otherwise would flow, which is no agreement and a potential work stoppage?

MR. McDONELL: No, I would agree with that. I think our philosophy with bargaining is we recognize that it is not practical to be able to have wage rollbacks. Instead, we look for other ways, and I thing we have been fairly successful in finding greater flexibility, or at least constraining costs. In our evidence, I think we give numerous examples of where we have achieved other savings as opposed to a direct wage rollback.

152. Despite the increased difficulty in controlling compensation costs due to Hydro One's unionized environment, the company has outperformed comparable organizations in maintaining compensation levels since 1999.[133]

Table 11: Average Base Rate Percentage Change for Selected Classifications (1999-2017)

Organization	PWU	Society
Hydro One	62%	36%
Ontario Power Generation	87%	37%
Organization	PWU	Society
Bruce Power	110%	43%
Independent Electricity System Operator	NA	40%

Pensions

153. In 2010, the Board directed Hydro One to demonstrate progress toward bringing its pension plan in line with the sector.[134] Employee pension contributions have substantially increased for all employee groups since 2013. The chart below demonstrates the increased share of pension contributions that is borne by PWU

[133] Exhibit C1, Tab 2, Schedule 1, Page 40 of 51
[134] Exhibit C1, Tab 2, Schedule 1, Page 42 of 51

represented employees.[135] Similar charts for Society represented and MCP pension plan members are also available in Hydro One's evidence.[136]

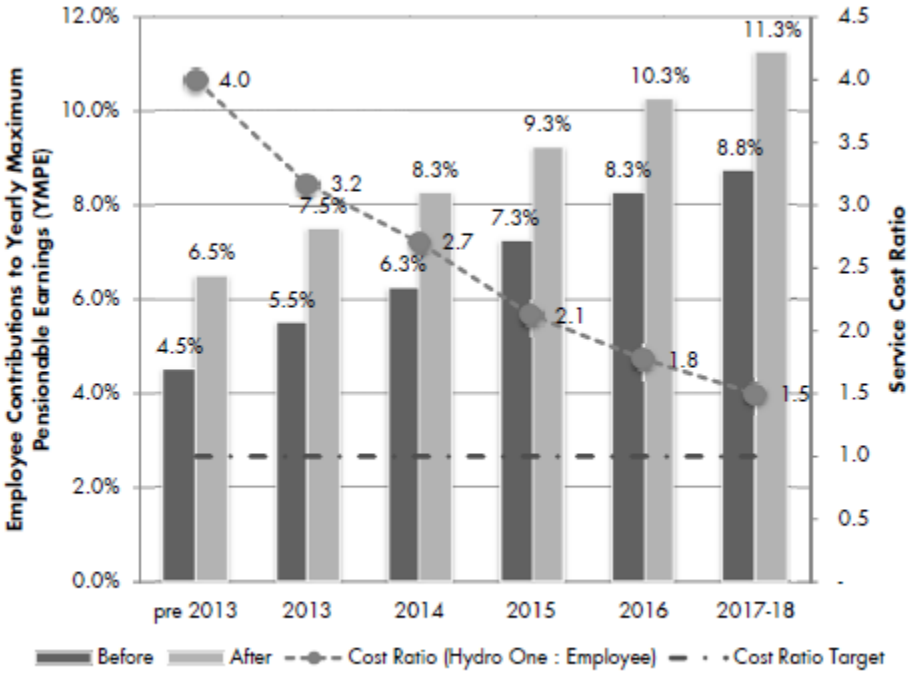


Figure 5: PWU employee pension contribution increases 2013-2018

154. The progress made in recent collective agreements with respect to pension costs have been significant. Compensation costs savings attributable to increased employee pension contributions are greater than $55 million through the test period.[137]

Table 13: Annual Savings from Increased Employee Pension Contributions (DX)

Year	$M
2018	$10.9
2019	$12.0
2020	$11.9
2021	$11.5
2022	$11.7

155. Modified pension eligibility dates and average earning calculations are further contributing to reducing future pension costs. Early undiscounted pension eligibility has been extended from the Rule of 82 to the Rule of 85, effectively delaying pension

[135] Exhibit C1, Tab 2, Schedule 1, Page 43 of 51
[136] Exhibit C1, Tab 2, Schedule 1, Pages 45-46 (Appendix A)
[137] Exhibit C1, Tab 2, Schedule 1, Page 44 of 51

eligibility for an average of one and half years. Final average earnings calculations are to be determined using five years instead of three years, reducing pension benefits. The new pension rules apply to all PWU represented employees and Society represented legacy pension plan members and are effective March 31, 2025.[138]

156. Hydro One has also been able to achieve savings by reducing the number of overtime hours worked. As demonstrated on the following table, overtime hours have declined in each year since 2013.[139]

Table 1

Year	Regular Hours	Overtime Hours Worked at Straight Time	Overtime Hours Worked at 1.5	Overtime Hours Worked at 2.0	Total Overtime Hours Worked
2012	13,503,501	7,908	220,370	767,249	995,526
2013	13,533,619	20,826	240,919	978,466	1,240,212
2014	13,746,075	9,188	236,621	858,416	1,104,225
2015	13,370,407	6,855	212,701	817,101	1,036,657
2016	13,812,981	11,763	160,705	830,654	1,003,122
2017	13,271,988	11,998	153,430	837,086	1,002,514
2018	14,199,900	10,253	183,216	761,286	954,755
2019	14,033,250	10,198	182,225	757,168	949,590
2020	14,005,200	10,171	181,748	755,186	947,104
2021	13,982,100	10,148	181,338	753,483	944,969
2022	13,970,550	10,126	180,942	751,835	942,903

157. The number of overtime hours is forecast to decline in each year through the test period. Hydro One notes that overtime is difficult to project and can vary from year to year as the majority of overtime is due to storm activity.

158. Hydro One's pension plan is now in a surplus position.[140] Board Staff has suggested that Hydro One should use that surplus to take a "contribution holiday", thereby reducing its current pension cost. The PWU disagrees, for two reasons. First, the forecast of any continuing surplus is based upon a point in time forecast.[141] The variables which factor into a pension solvency analysis are constantly changing. A reduction in employer contributions simply increases the probability that the pension

[138] Exhibit C1, Tab 2, Schedule 1, Page 42 of 51
[139] Undertaking JT 2.4
[140] Hearing Transcript, Volume 3, June 14, 2018, Page 30, lines 14-20
[141] In this case from December 31, 2016.

plan may swing back into a deficit situation, requiring special payments by the employer to the plan. This would result in unwarranted cost shifting to future ratepayers.

159. Secondly, Hydro One's ability to reduce its pension contributions is constrained by the provisions of the collective agreement, which prevents the employer from reducing its contributions below the level of employee contributions.[142] Notably this provision mirrors the 50-50 pension contribution sharing of the plans that the Board has used as the objective for Hydro One to achieve. However, for Hydro One to seek to use the surplus below that level would be a very inefficient use of the surplus, from a ratepayer perspective, since it would require $2.00 of surplus funds for every $1.00 of employer contribution reduction.

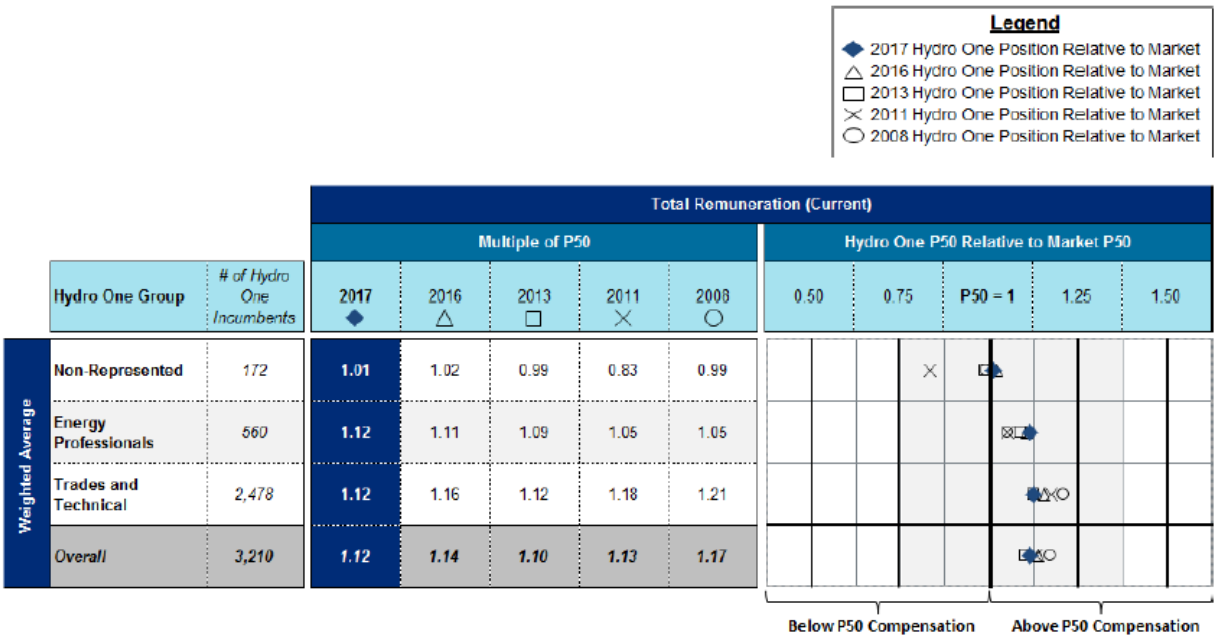
Mercer Study

160. Mercer's Compensation Cost Benchmarking Study evaluates Hydro One's compensation at the individual employee level against industry peers. This type of analysis can provide useful information in one aspect of the level of total compensation. However, individual employee compensation does not adequately reflect performance in total compensation cost control. As discussed earlier, decisions that lead to lower total compensation can lead to an appearance of poor performance at an individual level.

161. Mercer's study was originally filed with the application in March 2017 and an update was filed by Hydro One in April 2018.[143] The results of the updated Mercer study reflect the strides Hydro One has made since the 2015 collective agreements. The updated study shows Hydro One's weighted-average compensation to be 12% above the median.[144]

[142] Hearing Transcript, Volume 4, June 15, 2018, Page 1, lines 12-28
[143] Exhibit K1.1-2
[144] Exhibit K1.1-2, Mercer Study, Page 3

Table 1



162. In just one year, from 2016 to 2017, Hydro One's overall compensation relative to the median has declined by 2 percentage points. The change is even more significant for PWU represented employees (denoted "Trades and Technical" in the above chart) as compensation relative to the median has declined by 4 percentage points. Higher relative compensation for PWU represented employees in 2016 may be the result of lump-sum payments made in 2016 that will not continue into the future and, therefore, do not represent compensation trends.

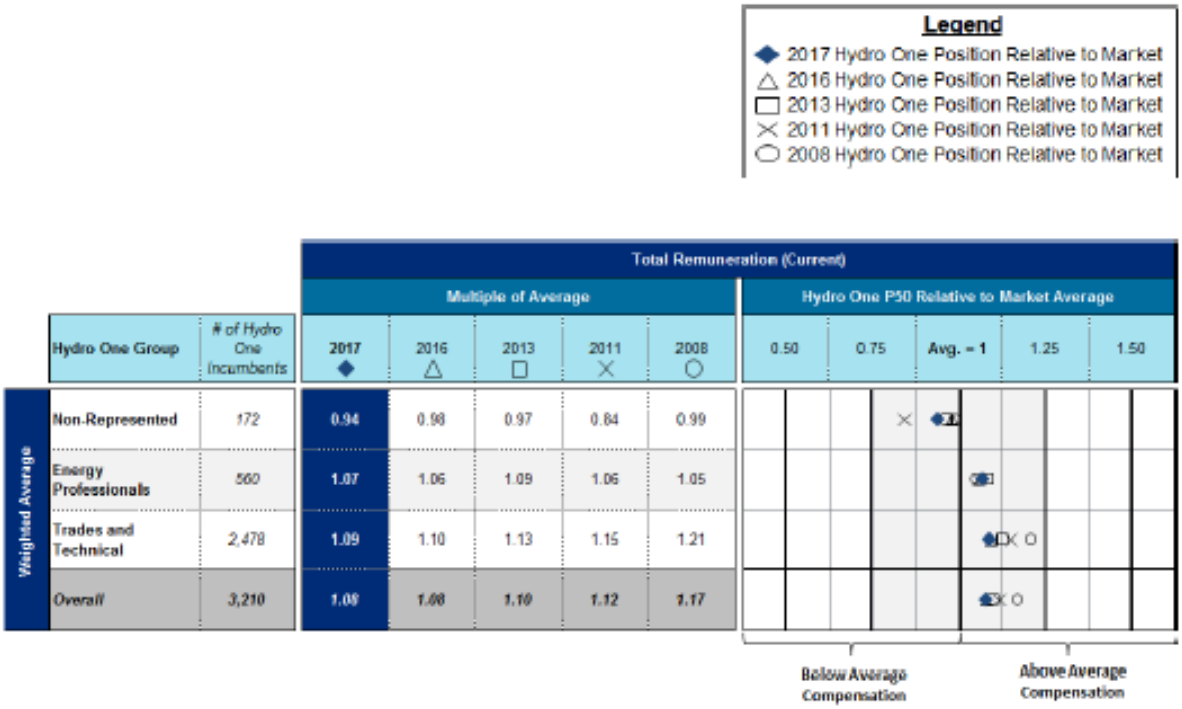
163. In an updated response to an interrogatory[145] Mercer explained that the market median had increased at a lower rate from 2016 to 2017 than it had from 2013 to 2016. That Hydro One compensation relative to the median, both for the PWU and overall, fell over this period indicates there has been a substantial turning point in the company's compensation trends. As compensation continues to increase at a rate below inflation, there is no reason to expect these positive trends to discontinue.

164. Mercer also provides a comparison of Hydro One compensation levels to the mean peer group wage. The median is typically used in this type of compensation study over the mean because the use of mean can cause the reference measure to be largely

[145] Supplemental IRs filed June 7th 2018, Page 39 of 94 – Revised Exhibit I, Tab 40, Schedule PWU-31

influenced by outliers. However, the median can be unduly influenced by changes to the peer group which has occurred between each of the Mercer studies. Within that context, it is appropriate to consider Hydro One's wages relative to the mean in compensation trend analysis, which is reproduced below.[146]

Table 8



165. Given the lower-than-inflation wage increases embedded in the application and overall decline in total compensation costs throughout the test period, Hydro One's current trend of moving toward the market median is likely to continue into the future.

166. Hydro One's ongoing progress in compensation cost control can also be demonstrated in relation to its overall revenue requirement.

[146] Exhibit K1.1-2, Mercer Study, Page 18

Total Compensation as a % of Revenue Requirement[147]							
	Bridge Year	Test years					Average Annual
	2017	2018	2019	2020	2021	2022	Change
Total Dx Compensation ($M)	607	634	639	627	612	618	0.38%
Total Revenue Requirement ($M)	1,468	1,517	1,564	1,611	1,684	1,726	3.30%
Compensation as % of Revenue requirement	41.34%	41.79%	40.84%	38.95%	36.34%	35.83%	

167. With a continued decline in complement and lower-than-inflation wage escalation, compensation declines as a share of the total revenue requirement over the course of the test period. In 2018 compensation comprises almost 42% of the distribution revenue requirement. By 2022, the share falls to below 36%. Similar trends can be seen in a chart provided in the application that compares compensation to total work program spend.[148]

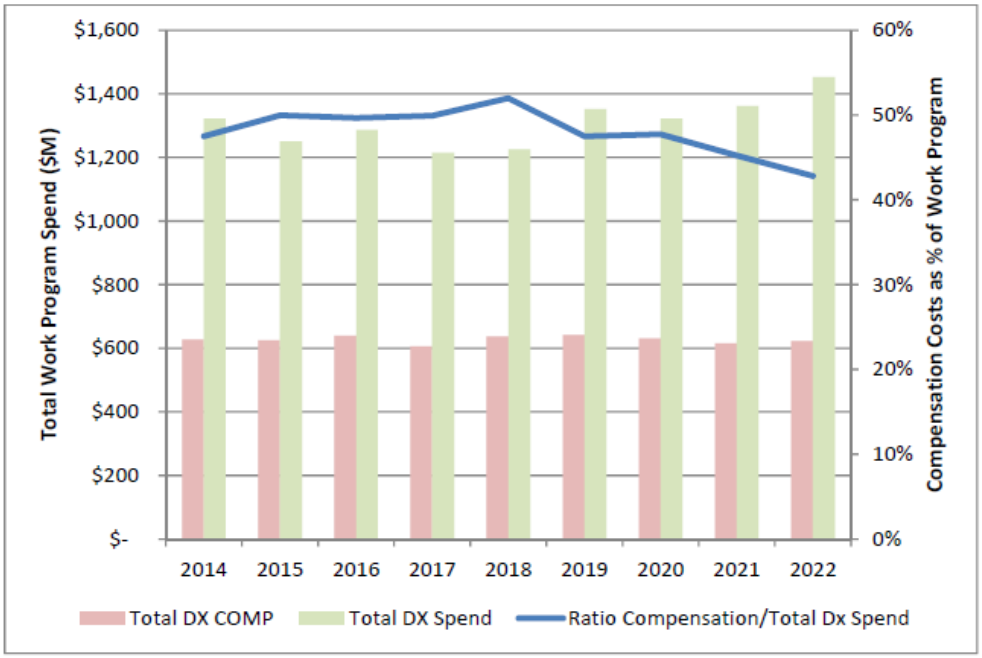


Figure 4: Hydro One Distribution Compensation vs. Total Work Program (OM&A and CapEx)

[147] Exhibit I, Tab 40, Schedule SEP-013, Attachment 1 & Exhibit Q, Tab 1, Schedule 1, Page 3 of 25
[148] Exhibit C1, Tab 2, Schedule 1, Page 34 of 51

168. The Board will no doubt receive submissions suggesting that it should disallow some portion of Hydro One's forecast compensation costs. The Board should not accede to those submissions, for a number of reasons. The first is to recognize the limitation of benchmarking evidence, particularly in the context of an application such as the present one:

a. The Mercer study is, at most, a snapshot of Hydro One's performance relative to certain peers at a point in time in 2017. Performance relative to a benchmark is a dynamic thing, and is likely to change with time. There is simply no evidence of what Hydro One's performance will be in the future relative to any benchmark, for any portion of the test period (particularly the later years). It is not capable of supporting any amount of disallowance.

b. Collective bargaining outcomes are not determined on the basis of benchmarking surveys. They are determined by the parties undertaking their legally imposed obligations to bargain in good faith, and the exertion of their bargaining power to achieve results in the parties' respective best interests. There is evidence that OPG obtained favourable outcomes in its most recent bargaining with the PWU and the Society. There is no evidence whatsoever that Hydro One had any ability to achieve absolute rollbacks in wage rates either then, or will have such ability in future collective bargaining with its respective unions.

c. The Board does have evidence of the very modest per employee compensation increases that Hydro One is forecasting and embedding in rates for the balance of the test period.

d. Insofar as the Board considers its performance relative to peers to be relevant, it has such evidence available to it. That is the evidence pertaining to OPG, Bruce Power, and the IESO. It is submitted that this evidence, which shows Hydro One has accomplished the lowest wage increases for both the PWU and Society since 1999, is far more probative and compelling than the Mercer study.

e. Board Staff propose an overall OM&A disallowance of $17 million, partially on the basis of non-executive compensation. The PWU submits that the disallowance of costs in circumstances where the utility could not actually achieve the lower costs is confiscatory and a denial of prudently incurred costs. It cannot result in a just and reasonable rate.

All of which is respectfully submitted.