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BY E-MAIL

July 3, 2019

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Hydro One Networks Inc.
Application for Rates
OEB File Number EB-2019-0082

In accordance with Procedural Order No. 1, please find attached the Ontario Energy Board staff interrogatories on the referenced application filed by Hydro One Networks Inc.

Original Signed by

Martin Davies
Project Advisor, Major Applications
Applications Division

Attachment

cc: Parties to EB-2019-0082

Ontario Energy Board Staff Interrogatories
Transmission Rate Application 2020-2022
Hydro One Networks Inc. (Hydro One)
EB-2019-0082
July 3, 2019

EXHIBIT A - ADMINISTRATION

A-Staff-1
Ref: Exh A/Tab 2/Sch 4/Attachment 1, p. 2

At the above reference, Hydro One stated the following:

> The TCB[1] study included a recommendation that Hydro One reassess its performance indicators with a view to reducing cost and improving performance. Specifically, the TCB study recommended that Hydro One: (i) establish corporate goals and objectives and identify existing and new metrics that support those goals and objectives; then (ii) implement a tracking and reporting framework and incorporate the metrics into the company's performance management process. Hydro One addressed this recommendation by developing an evolved scorecard, included in TSP Section 1.5, and a Performance Reporting Governance Framework, described in TSP Section 1.5.1.

a) Have all the TCB recommendations been fully addressed by "developing an evolved scorecard" and "a Performance Reporting Governance Framework"?
b) Please explain how the proposed significant capital spending increase outlined in this filing aligns with the TCB study recommendation of "reducing cost".
c) Please explain how a new evolving scorecard will address this deficiency.

A-Staff-2
Ref: Exh A/Tab 3/Sch 1/p. 23 and p. 35 Table 7

At the first reference above, Hydro One stated the following:

> Progressive Productivity savings total $286 million over the planning period and are included in the Transmission Business Plan in the form of:
>
> 1. $49 million in Progressive (Defined) savings associated with initiatives that have been identified but which have not yet been proven and verified through the productivity governance framework; and

[1] Transmission Total Cost Benchmarking

2. $237 million in Progressive (Undefined) savings which are included as placeholder in the Business Plan to be allocated to any future initiatives that have not yet been identified.

a) Table 7 at the second reference indicates an increase of approximately 53% in System Renewal spending from 2018 to 2024. Please state what has changed since the previous Transmission Filing to justify a 53% increase in System Renewal investments.
b) Please explain in detail how the Progressive Productivity savings were calculated.
c) Please state whether or not Progressive Productivity savings targets were established in whole or in part to mitigate the magnitude of the capital spending increase.
d) Please explain how the identified Progressive Productivity savings will be achieved. For example, how does Hydro One plan to achieve the $17 million in savings scheduled for year 2020?
    i. If the $17 million in savings isn't achieved, how is that going to affect ratepayers?
e) Please explain the reasoning for the anticipated Progressive Productivity Savings on an annual basis. For example, why is $17 million in savings scheduled for year 2020 and $39 million in savings scheduled for year 2021?

A-Staff-3
<u>Ref: Exh A/Tab 3/Sch 1/pp. 36-37</u>

At the above noted reference, Hydro One stated the following:

> While the planned rate of refurbishment does not keep up with lines demographics, the risk is managed by prioritizing line refurbishment investments based on detailed asset condition assessments. The pace at which a transmission line deteriorates varies depending on location and environmental and system conditions.

a) Does Hydro One's assessment of expected service life for specific transmission lines incorporate these factors? In other words, are transmission lines in areas with favourable locations, environmental and system conditions that would reduce deterioration assigned an extended service life?

b) What is the bookend range of ESL variability, from less favourable to more favourable locations?

A-Staff-4
Ref: Exh A/Tab 3/Sch 1/p. 39, Figure 4 Scorecard

a) Has Hydro One considered implementing a scorecard metric detailing the percent of projects completed as per plan? If not, why not?
b) Has Hydro One considered implementing a scorecard metric detailing the actual versus planned expenditures for the planned projects? If not, why not?

A-Staff-5
Ref: Exh A/Tab 4/Sch 1/pp. 1-3 and Handbook for Utility Rate Applications, October 13, 2016

Hydro One's 3-year Custom IR plan consists of rebasing the revenue requirement for 2020 through a cost of service approach, based on forecasted 2020 test year capital and operating costs. After rebasing the revenue in 2020 on a Cost of Service basis, Hydro One proposes a Custom Incentive Rate-Setting approach based on a Revenue Cap IR for the following two years (2021 and 2022). The revenue requirement for the rate year t is equal to the revenue requirement in year t-1 adjusted annually by the revenue cap index (RCI):

$$RR_t = RR_{t-1} \times (1 + RCI_t)$$

where:

$$RCI_t = I_t - (X + stretch) + C_t \pm Z_t$$

- I_t is the Inflation (i.e., Input Price Inflation or IPI), as determined annually by the OEB for the following rate year. Hydro One proposes an electricity transmission sector-specific inflation factor based on an analysis documented in PSE's evidence
- X is the base productivity factor representing the historical sector annual productivity trend.
- $stretch$ is a stretch factor to ensure a sharing of benefits of improved productivity and cost performance between shareholders and ratepayers over the plan term.
- C_t is Hydro One's Custom Capital Factor, determined to recover the incremental capital-related revenue requirement in each rate year necessary to support Hydro One's proposed Transmission System Plan, beyond the amount already recovered in the revenue cap-adjusted revenue requirement for that year

- Z is for any qualifying adjustment(s) for recovery of (capital and/or operating expense) for exogenous factors (e.g., major storm damage recovery, policy changes) that meet the OEB's requirement for Z-factors.

Hydro One has not included a growth ("g") factor in its revenue cap proposal, on the basis that there is little change in the transmission load forecast (and hence on the cost allocation of the charge determinants to be used for determining the Uniform Transmission Rates (UTRs) to recover the aggregate revenue requirements of all transmitters for each year.

Based on the Total Factor Productivity and total cost benchmarking analyses in the evidence of Power Systems Engineering Inc. (PSE), Hydro One has proposed base X and stretch factors of 0% and 0%. Thus, as proposed, Hydro One's Custom IR revenue requirement adjustment would be:

$$RevReqt_t = RevReqt_{t-1} \times (1 + (IPI_t^{Tx} - (0\% + 0\%) + C_t \pm Z_t))$$

a) Please confirm that, as proposed with a 0% base X and stretch factors, there are no productivity gain expectations in the 3-year Custom IR plan except for any that might be factored into the rebased revenue requirement for 2020. In the alternative, please explain.

b) In the OEB's Handbook for Utility Rate Applications (Rate Handbook), the OEB states the following:

   - Custom IR: Under this methodology, rates are set for five years considering a five-year forecast of the utility's costs and sales volumes. This method is intended to be customized to fit the specific utility's circumstances, but expected productivity gains will be explicitly included in the rate adjustment mechanism. Utilities adopting this approach will need to demonstrate a high level of competence related to planning and operations. Additional guidance on Custom IR applications is set out below.[2] **[Italics added]**

   With the proposed X and stretch factors set at 0%, please explain how the revenue cap adjustment satisfies the OEB's expectation in the Rate Handbook that "expected productivity gains will be explicitly included in the rate adjustment mechanism."

c) As proposed, the revenue requirement adjustment formula escalates OM&A by inflation, while the capital-related revenue requirement is adjusted by inflation and by the C-factor accounting for all forecasted capital additions per the Transmission System Plan beyond the inflation adjustment. Isn't Hydro One's

[2] *Handbook for Utility Rate Applications*, October 13, 2016, p. 24

Custom IR plan, as proposed, equivalent to a 3-year cost of service plan (i.e., with the revenue requirement rebased through a cost of service approach for 2020, with formulaic adjustments for inflation on OM&A and inflation and capex growth on the capital-related revenue requirement for 2021 and 2022). Please explain your response.

d) The OEB provides further discussion on the Custom IR plan expectations in the Rate Handbook:

- Index for the Annual Rate Adjustment: The annual rate adjustment must be based on a custom index supported by empirical evidence (using third party and/or internal resources) that can be tested. *Custom IR is not a multi-year cost of service; explicit financial incentives for continuous improvement and cost control targets must be included in the application. These incentive elements, including a productivity factor, must be incorporated through a custom index or an explicit revenue reduction over the term of the plan (not built into the cost forecast)*.[3] **[Italics added]**

Please explain how Hydro One's proposed revenue cap formula satisfies the emphasized section of the OEB's policy.

A-Staff-6

Ref: Exhibit A/Tab 4/Schedule 1
Decision with Reasons EB-2017-0049, March 7, 2019, pp. 31-33
Decision and Order EB-2018-0218, June 20, 2019, pp. 19-21

OEB staff notes that the proposed Custom IR plan, with respect to the adjustment formula for Hydro One's revenue requirement for the years 2021 and 2022, is similar in many respects, to Hydro One's current distribution Custom IR plan approved in EB-2017-0049, including the inclusion of a C-factor, and to Hydro One SSM's revenue cap plan for 2019-2026 recently considered and decided upon in EB-2018-0218.

a) Hydro One proposed a similar "revenue cap" adjustment formula, including a Custom Capital Factor (C-Factor) for its 5-year Custom IR plan (2018-2022) for distribution rate-setting in an earlier application (EB-2017-0049). The plan had distribution specific inflation, base X and stretch factors, and also differed in that the plan adjusted distribution rates rather than the aggregate revenue requirement.

   In its Decision with Reasons EB-2017-0049, the OEB determined that the stretch factor of 0.45% proposed should apply to the revenue cap index for adjusting Hydro One's distribution rates during the plan term, from 2018 to 2022. The OEB

[3] *Ibid*., p. 25

also determined that an incremental stretch factor of 0.15% should be included into the C-factor calculation, to incentivize further capital-related efficiencies for the capital program as forecasted in the Distribution System Plan (analogous to the Transmission System Plan filed in this application). This incremental 0.15% stretch factor was in addition to the 0.45% stretch factor approved for the rate adjustment formula and applied to both capital and OM&A.

Please provide Hydro One's views, with its reasons, on whether on an additional (incremental) stretch factor would be appropriate to provide an incentive for Hydro One to seek further efficiencies in its transmission capital program during the term of this Custom IR plan, similar to what the OEB approved for Hydro One's distribution operations.

b) On June 20, 2019, the OEB issued its Decision and Order pertaining to a multi-year revenue cap plan for the period 2019 to 2026 for Hydro One Sault Ste. Marie LP (Hydro One SSM). Hydro One SSM is an affiliated electricity transmission utility operating around Sault Ste. Marie, formed following the acquisition of Great Lakes Power Limited. In this decision the OEB determined that:

> The OEB approves the proposed productivity factor of 0%, a factor indicative of the change in productivity expected for the transmission sector as a whole. No party argued for a negative productivity factor even though both PSE and PEG calculated a negative TFP.
>
> …
>
> The OEB approves a stretch factor of 0.3% to provide an incentive to Hydro One SSM beyond the rate of inflation and balance the needs of its customers and shareholders during the term of the revenue cap framework.
>
> This stretch factor finding was made independent of the acquisition by Hydro One Inc. and the existence of a deferred rebasing period. Clearly, capital and OM&A savings are expected to result from the integration of Hydro One SSM into Hydro One Networks that is underway in 2019. The OEB finds that a stretch factor of 0.3% provides incentives to find further efficiency improvement beyond those proposed by the acquisition.

OEB staff acknowledge that the OEB's findings with respect to Hydro One SSM's revenue cap plan specifically pertain solely to that utility and that plan. However, Hydro One's proposed Custom IR is similar to the Hydro One SSM revenue cap plan, except for the inclusion of the C-factor in place of any ICMs, and is largely supported by PSE's slightly updated report. Please provide Hydro One's views on why a positive, non-zero stretch factor to incentivize further efficiency improvements would not be preferable to its proposed 0% stretch factor.

A-Staff-7

Ref: Exhibit A/Tab 4/Schedule 1/ Attachment 1
Exhibit A/Tab 2/Schedule 4/Attachment 1
EB-2016-0160, Exhibit B2/Tab 2/Schedule 1

PSE has included a sample of U.S. utilities for its TFP and Total Cost Benchmarking analyses. In its evidence filed in EB-2018-0218 and the updated evidence filed in this application, PSE states that it was unable to get the necessary data from other Canadian transmitters that it contacted.[4]

On Hydro One's previous transmission rate application, Hydro One commissioned Navigant Consulting Ltd (Navigant). To undertake a total cost benchmarking study. This was filed as Exhibit B2/Tab 2/Schedule 1.

Navigant's study is different in nature from PSE's methodology. Navigant's approach is not econometric; Navigant did not attempt to estimate a cost function. Instead, it examined capital and operating costs at various levels and for certain categories. Reliability data were included, but business condition variables were largely omitted. Costs were normalized per "asset", and assessment of cost performance was qualitative in nature. However, OEB staff observes that Navigant's study includes, in addition to a sample of U.S. utilities, two other Canadian utilities with electricity transmission assets and operations, specifically Manitoba Hydro and B.C. Hydro.

a) Please provide further explanation on the efforts to obtain data from Canadian electricity transmitters, and why Navigant was able to do so while PSE was not.

A-Staff-8

Ref: Exhibit A/Tab 4/Schedule 1/Attachment 1/pp. 5, 7, 17, 21
EB-2018-0218, OEB Staff IR 59 (Exhibit I/Tab 1/Schedule 59)
EB-2018-0218 Revised Public Redacted Technical Conference Transcript Volume 2 (January 15, 2019), p. 39/l. 6 to p. 162/l. 14
Decision and Order EB-2018-0218, p. 21

[4] Exhibit A/Tab 4/Schedule 1/Attachment 1/p. 21/section 3.1.2. In EB-2018-0218, PSE was asked an interrogatory seeking further explanation of the attempt to include other Canadian utilities with electricity transmission assets and operations in its sample – see EB-2018-0218 OEB Staff Interrogatory # 64 (Exhibit I/Tab 1/Schedule 64).

EB-2018-0218 Exhibit I/Tab 1/Schedule 65 (OEB Staff IR # 65)
EB-2018-0218 JT2.8
EB-2018-0218 JT2.9

On page 5 of its evidence, PSE notes the following changes have been made to its methodology in its evidence from that filed in the Hydro One Sault Ste. Marie revenue cap application:

> This report has been revised from the Power System Engineering, Inc. (PSE) report filed in the Hydro One Sault Ste. Marie LP (SSM) application found in EB-2018-0218. Our recommendations regarding the customer incentive regulation parameters remain unchanged and our findings are similar to the report previously filed. No changes to the study have been made except the modifications which are listed and explained below.
>
> 1. Hydro One Networks provided PSE with a revised business plan that includes modified OM&A and capital spending levels for the projected years of the study.
>
> 2. A second modification has occurred due to PSE identifying peak demand data that was incorrectly reported by the three Southern Companies (Alabama Power, Gulf Power, and Mississippi Power) included in the sample. This data has now been corrected.[1]
>
> 3. The third modification are slight revisions in plant additions in 2016 and 2017 made by Hydro One.
>
> 4. The incentive regulation period moves to 2020 to 2022 which means the OM&A spending is now escalated for 2021 and 2022 by I-X using the 2020 test year expenses rather than 2019.
>
> 5. Two minor corrections in the code were made relative to the prior research. The first is we are now calculating the asset prices prior to 1963 in calculating the capital benchmarks. The second is including only the observations in the TFP sample when aggregating the TFP components.[2]
>
> These five modifications have been incorporated into this revision and are the only changes made to the dataset and study methodology relative to the research filed EB-2018-0218 and EB-2018-0130.
>
> 1. This adjustment moved the TFP annual trend upwards by around 0.42%.
> 2. Both corrections had a minimal impact on the results with the effect of the change being a slightly lower TFP trend by around 0.16%.

PSE notes on page 17 of its evidence that the long-term TFP trend is -1.45%, a change of -0.16 percentage points from the study filed in EB-2018-0218. The historical data range for the TFP analysis was unchanged, from 2004 to 2016, as noted on page 7 of PSE's evidence.

a) Please confirm that only the changes in bullets 2, 3 (with respect to 2016 capital additions for Hydro One), and 5 relate to PSE's TFP analysis.

b) Please explain why PSE did not update its TFP and total cost benchmarking analysis with an additional year of data of 2017 actuals for both Hydro One Networks and the U.S. sample.

c) In its analyses documented in its evidence filed in this Application and in Hydro One SSM's application in EB-2018-0218, PSE has introduced a new constructed variable which it terms as a "loading" or "engineering construction index" to measure regional standards for the physical construction of networks to withstand climactic extremes for wind speeds, storms, ice loading, etc. OEB staff have used the term "hardening" as "loading" can also be used in the context of capacity or over-loading of electrical equipment.

   In the EB-2018-0218 Decision and Order with respect to Hydro One SSM's revenue cap plan, the OEB stated:

   > The OEB reserves judgement on the new "construction standards index" variable[57] provided in the PSE Report. This new variable is worthy of further consideration, yet the concept was not fully vetted in this proceeding. Further, the OEB questions its relevance to Hydro One SSM and its asset base.
   >
   > [57] PSE defines this new variable in Exhibit D, Tab 1, Schedule 1, pp. 25-26 and Appendix A. OEB staff used the term "hardening" variable, as it refers to the engineering standard to which network infrastructure must be constructed to withstand climactic conditions, such as wind and ice, in different regions (OEB staff submission, April 12, 2019, pp. 28-29).

   OEB staff recognizes that Decision and Order EB-2018-0218 was issued on June 20. 2019, after the filing of Hydro One's current Application. However, there was testing of this new variable during the EB-2018-0218 case, through interrogatories and during the Technical Conference. In particular, OEB staff raised a concern regarding the construction of the variable for Hydro One in that, based on Platts' GIS mapping, where all, or nearly all, of Ontario is used, while Hydro One has few or no transmission assets in a large portion of northern Ontario.

   Please explain why PSE (or Hydro One) did not update the "hardening" variable in light of the record in EB-2018-0218.

d) Please confirm that item 2 of the changes noted on page 5 of the updated PSE report correspond to the problem identified in OEB Staff Interrogatory #65 from the SSM proceeding.

e) Please confirm that item 5 of the changes noted on page 5 correspond to the problems identified in undertakings JT2.8 (aggregation) and JT2.9 (asset price) from the Hydro One SSM technical conference.

A-Staff-9

Ref: Exhibit 1/Tab 4/Schedule 1/Attachment 1
"Working Papers" for PSE Report filed as Attachment D/Tab 1/Schedule 1/Attachment 1 in EB-2018-0218

PSE has filed a report on the Total Factor Productivity and total cost benchmarking comparing Hydro One's transmission operations with a sample of U.S. utilities. The report is an update of similar evidence filed in the Hydro One SSM case (EB-2018-0218), with the changes documented of the PSE Report filed in this Application.

In EB-2018-0218, Hydro One, on behalf of its consultant, PSE, provided to parties the "working papers" (i.e., the data, models and other documentation) to allow requesting parties to understand and replicate the analyses documented in PSE's Report as filed in that case.

Please provide PSE's updated "working papers" with the data, models, and documentation to reflect the updated analyses documented in PSE's evidence in this current application.

A-Staff-10

Ref: Exhibit 1/Tab 4/Schedule 1/Attachment 1/p. 19

On page 19 of its evidence, PSE states the following as one of the reasons for recommending that the Custom IR "revenue cap" formula not include a growth factor:

> The existence of the capital factor is another reason we recommend not including the output growth factor in the formula. The capital factor incorporates any expected capital costs resulting from output growth. This makes including the output factor somewhat redundant when the capital factor is also present in the formula. However, PSE felt it was important to mention this output growth term in the discussion, for the sake of accuracy and completeness. In the case of a revenue cap formula where the output growth factor is not expected to be zero and a capital factor is not present, an output growth factor should be included in a revenue adjustment formula.

a) Is PSE stating that, with the custom capital factor increasing the annual allowed revenue requirement beyond what the standard I – X (inflation less productivity) formula would give, "growth" in demand for transmission services is *implicitly* factored in to Hydro One' proposed Custom IR formula? In the alternative, please explain.

b) If PSE believes that growth in demand is implicitly factored into the revenue requirement through the custom capital factor, does PSE also believe that, for the determination of Uniform Transmission Rates (UTRs) that aggregate the annual allowed revenue requirements of all involved Ontario electricity transmitters, it is also necessary to ensure that the charge determinants for the UTRs should also be adjusted to take into account the annual forecasted growth? Please explain your response.

c) If the response to b) is in the positive, please provide PSE's views on how Hydro One should forecast the charge determinants for its portion of the aggregate transmission revenue requirement on which the UTRs are calculated, to correspond with the growth factored into the C-factor-adjusted revenue requirement for each of 2021 and 2022.

A-Staff-11

Ref: Exhibit A/Tab 4/Schedule 1/pp. 10-11 Capital In-Service Variance Account

In Section 2.2 of this Exhibit, Hydro One has proposed a Capital In-Service Variance Account (CISVA) as a component of its proposed Custom IR plan. Hydro One proposes that the CISVA have the following features:[5]

1) The account will track the impact on revenue requirement of any in-service additions that are on a cumulative basis 98% or lower of the OEB-approved amount for each year of the Custom IR term;
2) For cumulative in-service additions that are 98% or lower of the OEB-approved level, the associated revenue requirement impact will be computed and reported on an annual basis in the variance account; and
3) At the end of the three-year term of the Custom IR Plan, in 2022, the sum of the variances in each year will be disposed of for the benefit of customers with the following conditions;
   - Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation; and
   - Account will be asymmetrical, meaning that should the cumulative in-service additions in any year of the Custom IR term exceed 98% of the cumulative OEB-approved amount for that period, no entry will be made in the variance account and no amount will be recoverable from

[5] Exhibit A/Tab 4/Schedule 1/pp. 10-11

ratepayers

a) Is Hydro One's proposal for the CISVA that same as Hydro One Networks proposed in its most recent distribution Custom IR plan in EB-2017-0049? Is it the same as the OEB approved in its Decision with Reasons EB-2017-0049? Please document any differences.

b) Hydro One has proposed a Custom IR revenue requirement adjustment with X = 0 (both base productivity and stretch factors are 0, as supported by PSE in its report). If the Custom IR plan is approved as proposed, please explain how the first condition of item 3) will be calculated:

- Revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains will be excluded from the calculation

What will be "verifiable productivity gains"?

A-Staff-12
<u>Ref: Exhibit 1/Tab 4/Schedule 1/Attachment 1</u>

PEG may wish to exclude certain operation, maintenance, and administrative ("OM&A") expenses from the US data that they use in this proceeding out of concerns about structural changes in the U.S. transmission industry. They may need to remove analogous costs from Hydro One's expenses. The excluded costs include those for load dispatching and system planning, which are often handled by regional transmission organizations and other independent system operators.

a) For all years covered by the PSE study, please provide estimates of Hydro One's OM&A costs that are included in the PSE study which correspond to the following FERC accounts. We provide the RRR account numbers that we believe might match the FERC accounts excluded from the PEG study. The list includes the miscellaneous account, where sizable restructuring and/or RTO costs have occasionally been recorded. If Hydro One does not wish to provide a more exact customized calculation, providing data for each of the suggested RRR accounts will be sufficient. PEG does not need itemization of the various 561 and 569 accounts for Hydro One; a total for these accounts would suffice.

- Account 561: Load Dispatching (RRR account 4810)
- Account 561.1: Load Dispatch-Reliability (RRR account 4715 or 4810)
- Account 561.2: Load Dispatch-Monitor and Operate Transmission System (RRR account 4715 or 4810)

- Account 561.3: Load Dispatch-Transmission Service and Scheduling (RRR account 4715 or 4810)
- Account 561.4: Scheduling, System Control and Dispatch Services (RRR account 4715 or 4810)
- Account 561.5: Reliability, Planning and Standards Development (RRR account 4715 or 4810)
- Account 561.6: Transmission Service Studies (RRR account 4715 or 4810)
- Account 561.7: Generation Interconnection Studies (RRR account 4715 or 4810)
- Account 561.8: Reliability, Planning and Standards Development Services (RRR account 4715 or 4810)
- Account 566: Miscellaneous Transmission Expenses (RRR account 4845)
- Account 567: Rents (RRR account 4850)
- Account 569.4: Maintenance of Miscellaneous Regional Transmission Plant (RRR account 4715 (RRR account 4715 or 4810))

A-Staff-13

Ref: Exhibit 1/Tab 4/Schedule 1/Attachment 1/ p. 31
EB-2018-0165 Exhibit L3/Tab 1/Schedule 2 (Interrogatory OEB Staff-2 on PSE's Reply Report filed in the Toronto Hydro-Electric System Limited 2020-2024 Custom IR proceeding)

PSE states the following on page 31 of their report:

> We determined the relative levels of utility plant asset prices for 2012 by using the City Cost Indexes for electrical work in RSMeans' Heavy Construction Cost Data.

In their response to L3-Staff-2 in EB-2018-0165 PSE stated:

> PSE has a paper copy of the 2012 book. The page containing the year of the data underlying the City Cost Indexes states: "Index figures for both material and installation are based on the 30 major city average of 100 and represent the cost relationship as of July 1, 2011." PSE used the 2012 RSMeans book to levelize the capital in the year 2012.

a) Please confirm that, for its work in this proceeding, PSE used the 2012 RSMeans book data to levelize its costs in 2012. In the alternative, please provide a similar discussion from the RSMeans book that PSE used for its work in this proceeding.

A-Staff-14
Ref: EB-2018-0218, Exhibit 1/Tab 1/Schedule 72 (OEB Staff Interrogatory #72)

In part e) a) of this interrogatory response on PSE's report filed in the Hydro One Sault Ste. Marie revenue cap plan application (EB-2018-0218), PSE states that:

> Yes, PSE …has used the Driscoll-Kraay approach to correct for autocorrelation within the sample. As stated in Section 3.4.2 of the PSE report, this correction for autocorrelation does not alter the underlying coefficient values and thus does not alter the benchmark result. PSE uses the Driscoll-Kraay standard errors to test statistical significance of the included variables, but this does not alter the estimates themselves.

In part e) b) of the same interrogatory response, PSE states that:

> PSE used the standard Driscoll-Kraay approach to correct for autocorrelation in the standard errors found in the STATA software package. No choice was made, nor is one available to be made for a specific time period.

In part h) of the interrogatory response, PSE lists steps in order to replicate their model:

> PSE only used STATA to estimate the Driscoll-Kraay standard errors. The working papers contain all of the code PSE has for STATA. If one is trying to re-produce the STATA results, the steps to produce the STATA results are 1) import the data, 2) declare the data to be a panel dataset, 3) create the variables needed for the regression, and 4) use the Driscoll-Kraay procedure with the command "xtscc".

Here "xtscc" is a command in the STATA econometric software package.

a) Please confirm that correcting for autocorrelation (if present) is necessary in econometric benchmarking for unbiased standard errors and valid t-stats.

b) In attempting to replicate PSE's model, PEG implemented the "xtscc" command in STATA but seeks further clarification regarding the command options that PSE used. Please confirm that STATA allows the "xtscc" user to specify the number of periods up to which the residuals may be autocorrelated with the lag(#) option. For example, if the user enters "lag(1)", then the package implements an MA(1) autocorrelation correction. Given that PSE originally said "no choice was made, nor is one available to be made for a specific time period," did PSE not specify this option? If not specified, what is the command's default?

A-Staff-15
Ref: Exhibit A/Tab 4/Schedule 1/Attachment 1
Exhibit H/Tab 1/Schedule 2, p. 3.

On page 23 of its report, PSE stated:

> PSE used a definition of "cost" for Hydro One that allowed us to achieve comparability with the definition used for the U.S. sample. The cost of transmission services purchased by U.S. utilities from other utilities is removed from the cost definition for the U.S. sample. Subtracting "transmission of electricity by others" expenses (Uniform System of Accounts category 565, on page 321 of FERC Form 1) creates a more comparable cost definition to Hydro One and, if not subtracted, would create an unfair advantage to Hydro One, since certain U.S. utilities would have inflated expenses without commensurate output values. PSE also subtracted pensions and benefit expenses from the cost definition. Given the different healthcare structures between Canada and the U.S., this expense category could slightly inflate U.S. costs relative to Hydro One.
>
> The transmission cost definition also includes an allocated amount of administrative and general (A&G) expenses (see page 323 of FERC Form 1).

On page 3 of Exhibit H/Tab 1/Schedule 2, Hydro One stated:

> Hydro One Transmission proposes to continue to record the difference between the actual Rights Payments paid and those approved by the OEB as part of 2020-2022 Transmission Rates.

a) Are the Rights Payments tracked by the Rights Payments account reported in Transmission Account 4850 Rents? If not, please provide the account number where Rights Payments are reported and explain what rights are being addressed by this account.

b) Is the Rights Payments account still limited to rights payments made to railroads and governmental entities? What percentage of all rights payments are eligible for tracking in the Rights Payments account?

c) Please confirm that the PSE productivity and benchmarking studies included these rights payments for both the U.S. utilities and Hydro One.

EXHIBIT B – TRANSMISSION SYSTEM PLAN

B-Staff-16

Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, pp. 22-23 and p. 28.

At the first reference above, Hydro One stated the following:

> The large industrial customers that are directly connected to Hydro One's transmission system are a critical part of Ontario's economy and, together, accounted for 1,785 MW of electricity demand in 2017, with an estimated 4% direct contribution to Ontario's GDP and a 28% contribution to Ontario's industrial GDP. These include, for instance, customer facilities for steel production, auto manufacturing, pulp and paper, chemical

> processing and mining. Typically, reliability and power quality for these large industrial customers are significant factors for their decisions to locate in and remain located in Ontario. Transmission outages or power quality issues can cause significant and costly interruptions to industrial processes and customer equipment, which in turn can affect company safety, performance, and employment. Hydro One developed a plan that brings reliability and power quality to these customers and which supports their businesses and Ontario's economy. These customers are sophisticated and well aware of the trade-offs between cost and reliability/power quality risk.

At the second reference above, Hydro One stated the following:

> The key outcomes that Hydro One seeks to achieve through implementation of the asset management process and capital expenditure plan as set out in this TSP include, but are not limited to:
>
> - Customer Focus: power quality improvements; improve customer reliability

a) Have customers asked specifically for power quality <u>improvements</u> and <u>improved</u> customer reliability? Please provide details to demonstrate this request.

b) Do industrial customers sensitive to reliability and power quality issues pay a premium rate to recognize their demand for superior service levels, relative to the requirements of smaller, less-sensitive loads?

c) Has Hydro One been directed to trade-off its cost of service versus the level of reliability and/or power quality risks for industrial customers by an external authority, or is this an internal decision that has been made by the company?

d) Given that Hydro One transmission does not directly serve most residential, small commercial and small industrial loads, is there a risk that the HONI transmission customer engagement process is buffered from receiving direct transmission rate feedback from most end-use customers?

    i. If yes, how does Hydro One mitigate that situation?

B-Staff-17

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p. 25, Figure 5.</u>

a) Under Customer Experience, what does "Foster innovation in the business to adapt to changing customer requirements and market opportunities" mean and how will success be measured?

b) Under Operational Effectiveness, what does "high level of reliability and quality" mean and how will success be measured?

    i. Are any specific costs associated with implementing this priority identified in this filing?

c) Please explain why "Invest in assets to better service customers" is included as a priority under Financial Strength.

B-Staff-18
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p. 26, Figure 6.</u>

a) Please explain how Figure 6 demonstrates a close alignment between Hydro One's planned transmission investments and the company's strategic priorities.
b) Under the Reliability Outcomes heading, please explain the reason for the jump in SAIDI from 2017 to 2018, given that this graph excludes Force Majeure (FM) events.
c) How is the significant projected improvement in SAIDI from 2018 to 2019 onward being achieved?
d) Under the Safety and Environment heading, please explain what "$3.5B which mitigates safety risk" means.
e) Under the Safety and Environment heading, Hydro One notes that $407M for targeted transmission line insulator programs. How does Hydro One prioritize these replacements, assuming that insulator failure presents a safety risk and given that the program spans many years?
f) Under the Reliability heading, please quantify the anticipated improvement in reliability associated with each bullet point listed.
g) As part of this filing, Hydro One has identified $681M in Productivity Savings over the forecast period.
    i. Please explain the difference between Productivity Savings (as used in Figure 6) and Progressive Productivity Savings.
    ii. Please explain how Hydro One is going to achieve these savings without impacting the overall system reliability, safety and performance.

B-Staff-19
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, pp. 41-42 and p.45.</u>

At the first reference above, Hydro One stated the following:

> For high-value assets, such as transformers, Hydro One's subject matter experts perform a thorough analysis and advise on issues such as equipment obsolescence, manufacturer support and conduct "repair vs. replace" evaluations. All transformer replacements require review by subject matter experts who prepare Transformer Assessment Reports that are used to validate investment decisions.

At the second reference above, Hydro One stated the following:

> In summary, the investment planning process consists of the following steps:
>
> 1. <u>Investment Planning Context</u>: Hydro One draws on multiple sources of input in the development and prioritization and optimization of the investment plan consistent with Hydro One's Strategic Business Objectives and the OEB's RRF. The investment plan is guided by: (i) strategic vision, (ii) planning and other relevant economic assumptions, (iii) customer engagement feedback, (iv) delivery of key outcomes, and (v) overall assessment of the needs of Hydro One's assets, customers and other stakeholders;

a) How are the resulting projects prioritized if more projects are identified than can be completed in one year or within the planning period?
b) How is the total overall capital spending envelope determined and optimized?
c) Who sets the overall spending envelope and what parameters are used in the decision?
d) Is "Investment Planning Context" the step where overall spending envelopes are determined? If not, where does that occur?
e) How is spending optimally allocated between investment categories?
f) Are budget envelopes set independently of the asset management process?
g) Please provide detailed explanations and specific examples of how "repair vs. replace" evaluations are conducted for different asset classes, including the parameters used in the evaluations and how decisions were made based on results of the evaluations.
h) Please provide a continuity table showing transformer replacement expenditures across the historical, bridge and forecast years. If appropriate, the table may be categorized by transformer size and/or functionality.

B-Staff-20
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p.43.</u>

At the above noted reference, Hydro One stated the following:

> This station-focused approach addresses infrastructure that is aging and in poor condition, and integrates OM&A and capital programs across multiple disciplines. Hydro One has established a recurring 7-10 year assessment cycle that enables all necessary renewal work to be performed at each of the 294 transmission stations during the cycle. This ensures that asset needs at all stations are reviewed on a recurring basis, which may or may not result in the need for investment after applying the ARA process. By developing and implementing integrated investments for each station, this approach enables Hydro One to efficiently use outages and to minimize the total number of outages required to complete necessary renewal work. The candidate investments identified through the Asset Management process include station-specific packages of work that have been developed in accordance with the established assessment cycle.

a) Has this station-focused approach historically reduced Hydro One's costs?
b) Please show stations capital spending trends before and after this change was implemented.
c) Please rank the relative impact of this change on Hydro One's project delivery convenience, Hydro One rate base growth, improved customer service, reduced rates, and any other material parameter.
d) How does Hydro One's 7 – 10 year assessment cycle compare with the practices of its industry peers?

B-Staff-21

Ref: (1) Exh B/Tab1/Sch 1/TSP Section 1.1, p.44,
(2) TSP Section 1.3, Attachment 4, pp. 1-2
(3)TSP Section 2.1, Attachment 4, p.31.

At the first reference above, Hydro One stated the following:

> In response to concerns raised during the EB-2016-0160 proceeding, Hydro One has implemented an improved eight-step investment planning process. Key improvements to the investment planning process include:
>
> - Consistent scoring for safety, reliability and environmental risk mitigation based on new standardized frameworks;
> - Clear definitions of risk impacts to enable consistent scoring across investment types, and calibration sessions to ensure standardized scoring practices; and
> - Challenge sessions, which are facilitated sessions held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

At the second reference above, Hydro One stated the following:

> In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model[6] needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

At the third reference above, Hydro One stated the following:

> Reliability consequence information is based on realistic customer outcomes for escalating levels of consequence based on Hydro One's experience.

a) Are the standardized frameworks based upon quantitative analysis and supported by adequate data to be replicable?

b) Is risk calculated to determine reliability risk associated with each asset under analysis:
   i. From the perspective of the asset?
   ii. From the perspective of the system?
   iii. From the perspective of Hydro One?
   iv. From the perspective of the ratepayer?

c) Given that Hydro One is not using a quantitative Reliability Risk Model (RRM) tool to estimate the marginal impact of reliability of different investments, please describe how reliability consequence is determined based on "Hydro One's experience".

B-Staff-22

Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p.45, and TSP Section 3.0, p. 5.

At the first reference above, Hydro One stated the following:

> 4. Prioritization and Optimization: The results of the risk assessment are translated into risk scores, which are used to generate an initial prioritization and optimization of investments. Following the initial prioritization and optimization, facilitated challenge sessions are held with a broad set of stakeholders to (i) review the prioritized portfolio, (ii) confirm non-risk considerations including productivity, (iii) discuss investments on the margin, and (iv) make trade-offs

At the second reference above, Hydro One stated the following:

[6] Reliability Risk Model

> Prioritization and Optimization: Based on risk-based prioritization and optimization through the enhanced planning process, candidate investments that are expected to most effectively mitigate the highest risk for the least cost should be performed first. For example, this is demonstrated through the prioritization and optimization of capital station sustainment work at Port Hope TS (ISD SR-05) to address emerging asset needs over a candidate investment at Havelock TS.

a) How is productivity (as used in the first reference above) assessed, quantified and integrated into these decisions? Please provide concrete examples.
b) Has the project portfolio been charted to show the risk delta achieved per dollar spent for all projects?
    i. If not, why not?
c) Please provide other examples of project prioritization to demonstrate that Hydro One is following a diligent and repeatable approach.

B-Staff-23

Ref: (1) Exh B/Tab1/Sch 1/TSP Section 1.1, pp.49-50, Figure 10,
(2) TSP Section 1.4, p.10.
(3) TSP Section 1.4, Attachment 15, p. 2

At the first reference above, Hydro One stated the following:

> Figure 10 shows the forecasted cumulative number of assets that will exceed their expected service life during the 2019 to 2029 period in the absence of any planned or unplanned replacements. Over this period, the number of assets that are beyond the expected service life in these asset classes would increase by 1.8 to 3.6 times current levels.

At the second reference above, Hydro One stated the following:

> The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition.

At the third reference above, Hydro One stated the following:

> **Investment Development**
> Hydro One’s transmission assets are replaced as condition warrants through rigorous

> testing. However, a backlog of asset condition testing has developed for assets such as conductors and shieldwire, where a large portion of the asset base is approaching it's Expected Service Life ("ESL").

a) Please explain why the "1.8 to 3.6 times" statistic is meaningful in this context.
b) Hydro One has recently changed its expected service life for conductors from 70 years to 90 years, indicating that there is a significant range of uncertainty associated with Hydro One's expected asset service life values. Is Hydro One able to demonstrate that similar adjustments are not required for other asset classes, or that further adjustments are not needed for conductors?
c) Is Hydro One able to demonstrate quantified correlations between exceedance of expected service lives for individual asset classes and system reliability performance? If yes, please provide tables showing these relationships.
d) Is conductor-km as used in Figure 10 above the same as circuit-km? For example, if there is a 1 km three phase transmission line strung with quad bundled conductor, is that equal to 12 km or 1 km?
e) Has Hydro One recorded any increase in the rate of conductor failures or outages caused by conductor failures?

B-Staff-24

Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, pp.48-49 and TSP Section 1.3, Attachment 4, pp. 1-2.

At the first reference above, Hydro One stated the following:

> In developing the TSP, Hydro One recognized that execution of the plan will take place in the context of the broader Ontario power system. In determining the timing and pacing of its investments, Hydro One considered both its own ability to execute capital and OM&A work efficiently and its ability to secure planned outage time to minimize impacts on customers and other stakeholders in Ontario. As a result, it has planned the pace of renewal work so that certain critical work to reduce risk on the system could be completed in the next five years to ensure that transmission assets are in service and not subject to increased outage constraints resulting from increased failures or additional maintenance that would make the work more difficult to complete.

At the second reference above, Hydro One stated the following:

In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model[7] needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

a) Is the described situation expected to change beyond the five-year planning horizon?
b) Please show the quantified analysis used to determine which "critical work" must take place to reduce risk on the system, given that the METSCO report (filed under TSP Section 1.4 Attachment 13) indicates that Hydro One's risk analysis does not adequately measure the system reliability risk associated with individual assets.

B-Staff-25

Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p.50 and Exh A/ Tab 3/Sch 1,p. 26, Table 5

At the first reference above, Hydro One stated the following:

System Access and System Service
The TSP funds $947 million of System Access and System Service capital that is required over the planning period to provide transmission access and additional capacity for new customer connections and to implement regional development plans that were developed jointly with customers, transmitters, distributors and the IESO. These investments will result in the addition of seven new transformer stations, ten customer-owned stations and 272 circuit km of new or upgraded transmission lines. Major projects include the development work for the North-West Bulk transmission expansion, new transmission switching and lines facilities to support load growth in the Leamington area, transformation and lines at Milton Switching station, and upgrades/expansion in Barrie and Toronto areas.

The second reference is Hydro One's 2020-2022 Load Forecast

a) Given that Hydro One's peak load is forecast to decline throughout the planning period (per Table 5 above), are there areas in the system where peak load is dropping off significantly to offset these identified areas with growing loads that require additional localized system capacity?

[7] Reliability Risk Model

i. If yes, please explain how Hydro One prioritizes replacement of assets that are beyond their expected service lives in these shrinking load areas, given that the peak loading of the associated assets is declining each year.

B-Staff-26
Ref: Exh B/Tab1/Sch 1/TSP Section 1.1, p.52

At the above noted reference, Hydro One stated the following:

> Approximately $590 million of the identified savings opportunities are related to Operations (Operations OM&A, Operations Capital, Progressive Operations (Defined Capital) and Progressive Operations (Undefined Capital), approximately $44 million in savings are IT-related (OM&A and Capital) and approximately $70M in savings are related to Corporate Initiatives (OM&A and Capital).
>
> Hydro One expects to achieve these significant cost savings over the forecast period through good planning and effective execution of the TSP.

a) Please categorize the projected capital savings as: i. Capital delivery efficiencies; ii. Capital project scope reductions; iii. Capital projects deferred or eliminated.
b) Please categorize the projected OM&A savings as: i. Staff reductions; ii. Contractor invoice reductions; iii. Consumable reductions.
c) Are there any other savings not identified above? If yes, please quantify.
d) Is "good planning and effective execution of the TSP" a different approach than has been applied in past test periods?
    i. If no, how will savings be produced?
    ii. If yes, please provide a detailed explanation of what has changed and quantify, to the extent possible.

B-Staff-27
Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, pp.15-16 and p. 18.

At the first reference above, Hydro One stated the following:

> **Greater Ottawa:**
> The second cycle NA report for this region was published in June 2018. The NA

continues to reaffirm the needs identified in the first cycle RIP and has identified the need for the following additional system renewal investments over the 2020 to 2024 period:

- Arnprior TS: Transformer (T1/T2) Replacement (Part of SR-02);
- Longueuil TS: Transformer (T3/T4) Replacement (Part of SR-05);
- Slater TS: Transformer (T1/T2/T3) Replacement (Part of SR-02); and
- 115kV S7M Transmission Line: Refurbish line sections (SR Other Projects).

At the second above reference, Hydro One stated the following:

GTA North:
The second cycle IRRP phase led by the IESO is currently underway; with the RIP for this region to be initiated and developed upon the completion of this IRRP.

a) Given that the RIP for the second cycle has not yet been issued for the Greater Ottawa region, is it premature for Hydro One to be proposing these investments for implementation in the present application period?
b) Similarly, given that the second cycle IRRP phase led by the IESO is still underway for the GTA North region, is it premature for Hydro One to be proposing these investments for implementation in the present application period?
c) Could these investments be deferred into the next filing? If no, why not?

B-Staff-28
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, p. 19.</u>

At the above noted reference, Hydro One stated the following:

GTA West
In response to the RIP recommendations, this TSP contemplates the following investments over the 2020 to 2024 period:

- Connection of a new load station “Halton TS #2” (Project SA-03);
- Milton SS: Station Expansion and Connect 230kV circuits (Project SS-07); and
- Reconductor 230kV H29/H30 Transmission Line (SA Other Projects).

a) Please state whether the primary driver for the Reconductor 230 kV H29/H30 Transmission Line Project is conductor condition or ampacity.

B-Staff-29

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 2, p.48.

At the above noted reference, Hydro One stated the following:

> **7.17 Newton TS End of Life Transformers and Switchgear**
> Newton TS is a 115 kV/ 13.8 kV DESN station having transformers built in 1956 and supplies Alectra Utilities loads in the city of Hamilton. It has two station supply transformer of 67 MVA each supplying loads through its 13.8 kV switchyards. The customer load at the station is about 50 MW and is forecasted to stay at the same level in the foreseeable future. Hydro One in initial assessment has identified that both transformers and switchgear requiring refurbishment. The scope of refurbishment is subject to final asset condition assessment of Newton TS to be completed in 2017.

a) What was the result of the final asset condition assessment?
b) Has Hydro One updated the plans for the Newton TS based on these results? If yes, what was changed?

B-Staff-30

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 5, p.22, Figure 5-1.

a) Are updated current year peak load forecasts available for this area and any other planning regions which have identified the need for capacity-related asset additions/expansions? If yes, please provide revised figures for each region.
b) For each of the updated load forecast figures provided in part a), do the updated forecasts change any of the needs identified in the RIPs? If yes, please describe the resulting changes.

B-Staff-31

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 8, p.39, Table 7-2.

a) What is the present status of the Metrolinx electrification project timing?

b) What is the resulting impact upon the capacity upgrade projects identified in this RIP (and any other RIPs included in this filing which incorporate Metrolinx electrification needs)?

B-Staff-32

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 8, p.44, Table 8-2.

a) Have projects 1 & 2 been completed, are they in construction, or are they deferred to the present filing?
b) If projects 1 & 2 were deferred to the present filing, is the urgency of these projects overstated in this RIP?
c) Are projects 3 & 4 included in the present filing?

B-Staff-33

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 9, p.39.

At the above noted reference, Hydro One stated the following:

> In the medium load growth scenario, involving new mines and industrial load (one pumping station of the Energy East gas-to-oil pipeline development supplied from the Thunder Bay transmission system) and no change in the pulp and paper sector, the load is forecasted to increase to 400 MW in 2035.

a) Given that the Energy East project is no longer active, can the medium scenario now be reduced commensurately?
b) What is the impact on the requirements identified in this RIP?

B-Staff-34

Ref: Exh B/Tab1/Sch 1/TSP Section 1.2, Attachment 10, p.29, Figure 6-1.

a) Please explain the reason for the abrupt discontinuity between the historical and forecast period demand trends for the Kingsville-Leamington Subsystem.
b) Is an updated 2019 version of this chart available? If yes, please provide it.
c) Does the revised forecast change the need of any projects identified in the Regional Plan?

B-Staff-35
Ref: Exh B/Tab1/ Sch 1/TSP/ Attachment 11, p.24, Figure 5-1 and p. 39.

At the second reference above, Hydro One stated the following:

> As discussed in Section 5, the electricity demand in the London Area Region is expected to remain relatively constant over the study period (approximate growth rate of -0.3%). Load growth over the long term period is expected to be moderate (up to 1.5%) from 2027 to 2037. Long term forecast provides a high level insight of how the region may be developing in the future so that near and mid-term plans and ongoing projects in the region are best aligned with potential long term needs and solutions.

a) Please provide a more current update of Figure 5-1.
b) Does the load growth turnaround vs. the historical load shrinkage still exist in the updated forecast?
    i. If yes, what is changing over the long term to cause the forecast load growth turnaround?

B-Staff-36
Ref: Exh B/Tab1/ Sch 1/TSP/ Attachment 11, p.40, Table 8-2.

a) What is the primary driver for the replacement of transformer T5 at the Wonderland TS; capacity constraint, asset condition or other?
    i. If asset condition, what does the most recent asset condition report indicate about remaining life of this asset?
b) How critical is this transformer to serving local loads?
c) Can anything be done to defer this expenditure given the anticipated regional load shrinkage?

B-Staff-37
Ref: Exh B/Tab1/ Sch 1/TSP/ Attachment 13, p.26 and p. 34.

At the first reference above, Hydro One stated the following:

> Note 5: Parry Sound TS was placed in service in 1970 and has been supplying power to parts of the Region for almost 50 years. Field crews have recently observed that one of the two power transformers is in poor operating condition.

At the second reference above, Hydro One stated the following:

> Based on historical demand data and the station's net demand forecast, Parry Sound TS T1/T2 has already exceeded its respective normal supply capacity and will continue to do so over the study period. Parry Sound TS is a winter peaking station with a winter LTR of 52 MW. It had exceeded its LTR by as much as 6 MW in the winters of 2013 to 2016, however the 2017 winter peak was 8 MW below the LTR.

a) Has a more recent fulsome asset condition assessment been carried out on the Poor Condition transformers at Parry Sound TS since this report was written (August 18, 2017)?
    i. If so, who carried out the assessment and what were the findings/recommendations?
b) What caused the 2017 peak load reduction?
c) Please provide the 2018 peak load results.
d) Is this indicative of a trend change towards longer-term peak load decreases?

B-Staff-38
<u>Ref: Exh B/Tab1/ Sch 1/TSP/ Attachment 13, p.31.</u>

At the above noted reference, Hydro One stated the following:

> It is worth noting that there are potential bulk power system elements that are also at the end of their useful lives. These include 230 kV transmission lines D1M/D2M, E8V/E9V, and M6E/M7E. IESO will lead the bulk power system studies for these lines in coordination with Hydro One.

a) Is the asset condition assessment for these facilities Hydro One's responsibility?
    i. If no, please explain why not.
b) What will be the IESO's role in this analysis?

B-Staff-39
<u>Ref: (1) Exh B/Tab1/ Sch 1/TSP Section 1.3, pp.6-7 Figure 2,</u>
<u>(2) TSP Section 1.3, p.8,</u>
<u>(3) TSP Section 1.3, Attachment 1, p. 5</u>
<u>(4) TSP Section 1.3, Attachment 1, p. 15.</u>

At the first reference above, Hydro One stated the following:

> Hydro One's Transmission Customer Engagement Survey process yielded valuable feedback concerning the specific needs and preferences of its transmission-connected customers to shape Hydro One's investment plans.

At the second reference above, Hydro One stated the following:

> Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

At the third reference above, Hydro One stated the following:

> **Customer Outcomes**
> Hydro One and INNOVATIVE reviewed previously available documents and talked to customer-facing Hydro One staff in order to develop a list of customer outcomes that was included in the survey. Prior to being exposed to this list, an open-ended question designed to elicit outcomes in customers' own words was asked. In response to this open-ended question, transmission customers said they know Hydro One is doing a good job for their business based on reliability, and customer service/communication (both of which were included in the list of outcomes developed for the survey).

At the fourth reference above, Hydro One stated the following:

> **Performance Criteria:**
> Reduction in outages and interruptions, power supply, and customer service in terms of communication are top mentions for performance metrics.

a) Given that the "desire for good reliability at a competitive or low cost was universal", why doesn't Hydro One consider Cost as one of the Customer Outcomes to be ranked when setting priorities for Hydro One's business plan?

b) Is the reason Low Cost is not included in the ranked list of Customer Outcomes because it is ranked below the other identified outcomes (i.e. Safety, Productivity, Reliability, Outage Restoration, Power Quality, Customer Service, and Environmental Stewardship)?

    i. If not confirmed, please provide a revised ranking of Customer Outcomes that includes Low Cost, and provide the evidence on which Hydro One makes this ranking determination.

c) Regarding the Customer Outcomes, how did Hydro One translate the information gathered and represented in Figure 2 to actionable information?

    i. For example, do the results represented in Figure 2 suggest that Hydro One is not doing enough regarding "Safety"?

d) Please provide details on what changes Hydro One made to its capital expenditure planning processes (for example, by increasing or decreasing consequences within the risk management process) as a result of the findings in Figure 2 - Customer Outcomes. For each response below, please provide examples.

i. Did Hydro One change its approach to either Safety or Environmental Stewardship, and did that result in the acceleration or deceleration of certain CAPEX projects?

ii. How did Hydro One alter its productivity programs plans discussed in TSP Section 1.6 in response to customer feedback?

iii. Did Hydro One ask any follow-up questions that explain why customers do not seem to favour Hydro One emphasizing higher productivity, which implies that Hydro One would be trying to provide more benefit relative to its input costs?

e) Hydro One and Innovative developed the list of Customer Outcomes (Figure 2), however when asked "How do you know if Hydro One is doing a good job for your business?", Hydro One's customers did not reference Safety, Productivity or Environmental Stewardship. Is this a fair statement? If so, please explain this disconnect.

B-Staff-40
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.3, p.7.

At the above noted reference, Hydro One stated the following:

> The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:
>
> - Reducing the frequency of outages is more important than reducing the duration of outages. However, the most important issue is to reduce the number of day-to-day interruptions;"

a) Please explain how Hydro One incorporated the above noted key message into its planning process.

i. Please provide specific examples of how investment decisions were changed to prompt a reduction in frequency of outages in priority to reducing the duration of outages.

b) Approximately what percentage of Hydro One's transmission revenue requirement is paid directly by the direct connect customers that responded to the customer engagement survey process?

   i. What insight does Hydro One have with regard to the question of whether direct connect customers prefer scenarios with higher reliability and cost outcomes compared to the preferences of the average Ontario electricity consumer? Please provide details.

B-Staff-41

<u>Ref: (1) Exh B/Tab1/ Sch 1/TSP Section 1.3, p.8,</u>
<u>(2) TSP Section 1.3, Attachment 1, pp. 44-47,</u>
<u>(3) TSP Section 1.3, Attachment 1, p.116,</u>
<u>(4) TSP Section 1.3, Attachment 4, pp. 1-2.</u>

At the first reference above, Hydro One stated the following:

> The key messages and results received by Hydro One from the 2017 Transmission Customer Engagement Survey are as follows:
>
> - When presented with several investment scenarios, the majority of customers preferred investment levels in line with the investment plan that was before the OEB in the Prior Proceeding by at least a three to one margin. It is seen as reflective of the current approach which has served the system well, and a less risky option;

At the third reference above, Hydro One stated the following:

> You will note that the two middle scenarios, B and C, offer a relatively small change in reliability risk, but moving from B to C offers significant improvements in long-term reliability. The key difference between B and C is that B has larger future increases, while C has level future rate increases. The big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers.

At the fourth reference above, Hydro One stated the following:

> In its Decision in Hydro One's last Transmission Rate Application (EB-2016-0160) the Ontario Energy Board ("OEB") found that the model[8] needs further refinement and testing if it is to be used to convey to customers information about the value of capital

[8] Reliability Risk Model

investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations as discussed in TSP Section 1.4, section 1.4.2.14.

a) What was Hydro One customers' weighted-average preference (on a scale of 1 to 17) of the investment scenarios?
b) For each of the Scenarios A, B, C and D, how did Hydro One precisely quantify for the survey respondents that "[t]he key difference between B and C is that B has larger future increases, while C has level future rate increases"?
   i. Did Hydro One develop any example rate datasets to illustrate key differences between scenarios? Please provide examples that were presented to customers.
c) For each of the Scenarios A, B, C and D, how did Hydro One precisely quantify for the survey respondents that "[t]he big differences in reliability are in scenarios A and D. Moving from A to B creates a significant decline in reliability risk. Moving from scenario C to D generates both a long term reliability benefit and targeted reliability improvements for a small group of customers."?
   i. Did Hydro One develop any example reliability datasets to illustrate the differences between scenarios? Please provide examples that were presented to customers.

d) What efforts has Hydro One undertaken to determine how sensitive HONI customers are to the marginal trade-offs between costs and performance (e.g. reliability or power quality)?
e) Did Hydro One populate the Reliability Risk estimates in the above table using the Hydro One Reliability Risk Model?
   i. If yes, did Hydro One advise the customers answering the survey that "the Ontario Energy Board found that the model needs further refinement and testing if it is to be used to convey to customers information about the value of capital investments in terms of system reliability. A third party assessment completed by Metsco Energy Solutions Inc. has led to a similar conclusion and recommendations"?

B-Staff-42
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.3, pp.10-11, Figure 3.

At the above noted reference, Hydro One stated the following:

> Figure 3 illustrates the trend of the overall satisfaction results. In 2018, Overall Satisfaction was at the highest point in the past seven years at 90%, which is a 12% increase since 2016. The increase in overall satisfaction can be attributed to LDCs and generation customers. The main driver identified through analysis for higher customer satisfaction was customer communication and key account managers. The identified driver correlated with lower satisfaction was the ability to recall a planned outage.

a) Please explain what is meant by "The identified driver correlated with lower satisfaction was the ability to recall a planned outage."
    i. Should this sentence refer to "unplanned outages" as opposed to planned outages?
b) Please confirm that Hydro One's Customer Satisfaction metrics show no statistically significant correlation with:
    i. Any cost measure/metric.
    ii. Any reliability measure/metric, aside from the "recall of an unplanned outage".
c) Given that customer communications and key account managers have a statistically significant impact upon customer satisfaction metric, are there any cost saving measures that Hydro One could implement to reduce the cost of its customer interaction process?
d) Does Hydro One use the Customer Satisfaction metric to justify any CAPEX projects included in this filing?

B-Staff-43
Ref: Exh B-1-1/TSP Section 1.3 pp. 28-33 Appendix 2 and EB-2016-0160 *Decision and Order* Revised: November 1, 2017, p. 24

At the first reference above, Hydro One described how it incorporated feedback from the OEB's previous transmission rate decision in the area of customer engagement into its customer engagement activities for the present application.

At the second reference above, one of the areas in which improvements could be made is stated as follows:

The process should be started sufficiently in advance of filing the application to allow for timely input to be incorporated in a meaningful way and to improve the level of customer attendance.

a) Please provide some examples as to how the input received from the customer engagement process undertaken for this application was incorporated into it in a meaningful way.
b) Please state the level of customer attendance for the customer engagement process for the preceding application and for the current one on a comparable basis.

B-Staff-44
Ref: Exh B-1-1/TSP Section 1.3 pp. 28-33 Appendix 2 and EB-2016-0160 *Decision and Order* Revised: November 1, 2017, p. 24

At the second reference above, which is the previous transmission decision, one of the areas in which improvements could be made is stated as follows:

The information presented to the customers should be unambiguous and easy to understand.

At the first reference above, Hydro One described how it incorporated feedback from the OEB's previous transmission rate decision in the area of customer engagement into its customer engagement activities for the present application. Hydro One stated that with respect to ensuring that information presented to customers is easy to understand, the following had been done:

Finally, the design of the 2017 engagement survey included information that was purposefully written to ensure the content was unambiguous, sufficiently informative for customers to respond to, and easy for customers to understand. To gauge the quality and clarity of the information, the survey included a post-survey question asking "Did Hydro One provide too much information, not enough or just the right amount?" The result was that 76% of respondents believed the survey contained just the right amount of information.

a) Please explain why Hydro One believes that the views of customers on the amount of information presented would also be reflective of their views on the information being unambiguous and easy to understand.

B-Staff-45
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.6 and p. 10.

At the first reference above, Hydro One stated the following:

> The benchmarking and other studies described below demonstrate that Hydro One's practices and processes for managing its key transmission assets are aligned with industry best practices. In two areas; underground cables and overhead conductor, the study results recommended Hydro One increase its expected service life ("ESL") for these assets. Hydro One will review its management practices and decision making procedures to minimize life-cycle costs and more effectively manage risk for these assets based on these recommendations. However, as asset replacements in Hydro One's business plan are selected based on end of life of the asset, this has not impacted the current business plan.

At the second reference above, Hydro One stated the following:

> The results of this study based on current condition assessment data and historical overhead conductor replacement data, indicate that ESL for overhead conductors in the Hydro One transmission system should be approximately 90 years. Hydro One's assigned ESL for overhead conductors was set at 70 years before this study. The new ESL resulting from this study does not affect the current business plan as identified replacements are not age based decisions, they are based on verified asset condition.

a) Please describe the quantified relationship (if any exists) between Expected Service Life (ESL) and End of Life (EOL) for different asset classes or types.
b) Does the quantified relationship between ESL and EOL change for different asset classes or types of assets? If yes, please explain these differences.
c) Does the selected ESL for any of Hydro One's asset classes have any impact on Hydro One's determination of EOL for any assets within any of those classes (e.g. for conductors)?
d) Is ESL used to forecast longer-term conductor replacement requirements, or something else?
e) Does EOL change depending on the consequence of failure of specific assets in the same asset class?

B-Staff-46
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.7.

At the above noted reference, Hydro One stated the following:

> Metsco reviewed the Reliability Risk Model ("RRM") and found that the analytical underpinnings and functionalities of the RRM trail advanced industry system reliability practices where used in asset management. In making this observation, Metsco found that a number of utilities do not nor have not until recently attempted to formally forecast system reliability in a comprehensive manner and suggests the RRM as a customer communications tool to convey directional changes to reliability risk levels across spend scenarios, Metsco is of the view that the observed gaps pose no meaningful risks from an asset planning perspective. Hydro One must remain clear about the tool's purpose and the implications of its analysis.

a) Do the observed gaps identify the risk of mis-characterizing the confidence that specific reliability outcomes would be produced by selecting different capital expenditure scenarios for the purpose of communicating with customers?
b) Do Hydro One's ARA and AA processes produce dependable forecasts of future reliability performance based upon the different capital investment scenarios being evaluated? In other words, is the proposed capital spending envelope optimized with respect to a quantified expectation of system reliability performance?
    i. If yes, please provide the expected system reliability results for the different spending scenarios considered in the planning efforts that informed the capital spending proposed in this application.
    ii. If no, please explain how the proposed spending levels were optimized.

B-Staff-47
Ref: Exh B/Tab1/TSP Section 1.4, p.8.

At the above noted reference, Hydro One stated the following:

> More particularly, 80.5% of the asset condition assessments for Hydro One's transmission transformer fleet aligned with EPRI's PTX analysis based on dissolved gas in oil content and oil quality data. For the remaining 19.5% of assessments, the results of which were not well aligned, the majority of the differences are attributed to data issues such as oil cross contamination between tap changer and main tank oil.

a) Is Hydro One able to do anything to mitigate these data issues?
b) If yes, is Hydro One doing anything to mitigate them?

B-Staff-48
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.10.

At the above noted reference, Hydro One stated the following:

> Hydro One's volume of replacement over the plan period is higher primarily due replacement criteria that were not included in the EPRI report. These criteria include obsolescence concerns, safety concerns (e.g. lack of or insufficient arc resistance rating), change in system conditions (e.g. short circuit level), polychlorinated biphenyl ("PCB") mitigation per regulatory requirements and integrated investments.

a) Please quantify the departure from the EPRI expected levels of volume replacement in terms of:
    - number of breakers;
    - percentage of fleet; and
    - total replacement cost.

B-Staff-49
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.11.

At the above noted reference, Hydro One stated the following:

> The majority of utilities have a formal process and algorithm for assessing transformer condition with 75% of these utilities use a risk-based approach with condition and system criticality ranking highest for their algorithm inputs. Like Hydro One, most utilities do not allow the algorithm to trigger a replacement but also rely on the input of subject matter expert assessments.

a) Does this mean that the algorithm alone cannot trigger a replacement, or that the algorithm in no way affects the selection of potential replacement candidates? Please explain in detail.

B-Staff-50
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.12.

At the above noted reference, Hydro One stated the following:

> Hydro One's protective relay fleet consists of three technologies: electromechanical, solid state, and microprocessor. Electromechanical relays have the longest ESL and have a very reliable performance. At the time of the report, solid state relays account for 58% of all relays currently operating beyond ESL, which is a risk to safety and reliability as shown in TSP Section 2.2.1.3.

a) Has Hydro One improved its relay specification and selection process to ensure that future widespread adoption and implementation of new relay technologies does not produce similarly poor outcomes? If yes, please explain what has changed.
b) Based on the long ESL and very reliable performance of electromechanical relays, is Hydro One considering returning to broader application of such relays going forward? If not, explain why not.
c) Has Hydro One evaluated the different life cycle costs to ratepayers of using electomechanical, solid state and microprocessor relays?
    i. If yes, please provide those results.
    ii. If no, explain why not.

B-Staff-51
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.13.

At the above noted reference, Hydro One stated the following:

> EPRI has determined due to the current loading on Hydro One's low-pressure and high-pressure liquid-filled (LPLF and HPLF) cables that the suitable ESL should be increased to 70 years. Hydro One has previously been using 50 years as the ESL for these assets. The ESL is not used to trigger replacement. Replacement is triggered by asset condition.

a) Is the described extension of ESL reflected in reduced underground cable replacement program costs in the present application? If no, please explain why not.

B-Staff-52
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.16.

At the above noted reference, Hydro One stated the following:

> This study confirms that the majority of Southern Ontario falls under the C4 corrosion rate category, with small pockets of C5 corrosion rate zones. The resolution of the atmospheric corrosion map has been refined with more defined boundaries between the various corrosion zones. This information enables Hydro One to use the higher resolution of the Ontario Atmospheric Corrosion Rate Map to optimize the tower coating program and to maximize the steel tower lifecycle. Hydro One accepts EPRI's recommendation to use the updated Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province. Hydro One plans to address these recommendations by overlaying the updated atmospheric corrosion map with existing Hydro One Geographic Information System ("GIS") data, in order to more accurately assign corrosion zones to each structure.

a) Please provide a table correlating the tower re-coating projects proposed in this application with the Ontario Atmospheric Corrosion Map zones.
b) Please provide a map overlaying the tower re-coating projects proposed in this application onto the Ontario Atmospheric Corrosion Map.
c) Has EPRI's recommendation to use the updated Ontario Atmospheric Corrosion Map to make more accurate decisions about the degradation of steel structures throughout the province been applied in this application?
    i. If not, why not?
    ii. If yes, did doing so increase or decrease the annual planned re-coating investment levels over the plan period?

B-Staff-53
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.17.

At the above noted reference, Hydro One stated the following:

> Other types of 230 kV insulators should continue to be assessed periodically for signs and degrees of degradation. EPRI further recommends that linemen should check the integrity of these insulators prior to performing any live maintenance procedures due to potential safety issues. Considering the study results, Hydro One will prioritize the removal of specific polymer insulators in its current replacement program.

a) Please quantify the number of insulators affected by the described premature deterioration and the cost to replace all at-risk insulators.
b) Please categorize the priority of replacement by manufacturer, voltage, absence of corona rings and any other parameters Hydro One considers germane to the replacement program.
c) Has Hydro One modified its specification, procurement and design processes to ensure that similar polymer insulator issues are avoided in future widespread new technology implementations?
    i. If yes, please provide details.
    ii. If no, please explain why not.

B-Staff-54
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.21.

At the above noted reference, Hydro One stated the following:

> Hazard curve function analysis suggests that the removal rate in Region 2 is largely due to discretionary removal (planned replacement).

a) This key finding was identified for both the derivation of transmission substation transformer hazard functions and for Circuit Breaker hazard functions. Please quantify the delta between EPRI removal rate and Hydro One removal rate, in number of units, percentage of fleet and total cost of replacement for both the substation transformers and circuit breakers.

B-Staff-55
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.22.

At the above noted reference, Hydro One stated that “Half of utilities refurbish transformers to extend life.”

a) Does Hydro One refurbish transformers to extend life?

    i. If yes, please provide documented examples of refurbishment vs. retirement decisions.
    ii. If no, please explain why not.

b) If one exists, please provide the formula used by Hydro One to establish refurbishment investment limits, driven solely by estimated remaining service life (defined as ESL minus actual age).
    i. Once an asset has exceeded ESL, what is the maximum allowed refurbishment investment?

B-Staff-56
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.23, Table 8.

a) For Key Finding #1:
    i. What are the primary factors that cause concern at 44 years?
    ii. Are the factors of concern different for different types of breakers (e.g.: bulk oil, minimum oil, ABCB and SF6)?
    iii. If yes, does the 44 year "concern" threshold still apply across all breaker types?
b) For Key Finding #2, how are 1/3 of respondents able to run transmission breakers to fail, while the others do not? Is run-to-fail seen as a prudent operating approach for those respondents?

B-Staff-57
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, pp.27-28, Table 16.

a) For Key Finding #1:
    i. Is there an economically practical way to refurbish deteriorated housings to extend the replacement program over a longer period?
    ii. Is Hydro One retrofitting non-deteriorated K-Line insulators with larger corona rings to mitigate this issue?
    iii. How many Hydro One insulators are affected by this type fault?
b) For Key Finding #2:
    i. Why were these insulators installed without corona rings?

ii. Did Hydro One follow the manufacturer's recommended installation practice, or did Hydro One customize the installation design?
iii. Should these premature failures be characterized as a type fault or a design deficiency?
iv. How many Hydro One insulators are affected by this issue?

c) For Key Finding #3, how many Hydro One insulators are affected by this type fault?
d) For Key Finding #4, is Hydro One actively implementing this recommendation? If no, why not?
e) For Key Finding #8:
  i. Is the statement true regardless of manufacturer?
  ii. What percentage of silicone insulators have been damaged?
  iii. How many insulators does this represent?

B-Staff-58
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, p.32.</u>

At the above noted reference, Hydro One stated the following:

> Increased outcome definition: In 2017, Hydro One was able to translate the results of its investment plan into expected customer outcomes with greater specificity than it had in previous years, leading to 5 year targets for key scorecard metrics.

a) Does "greater specificity" as used here mean "greater precision", "greater accuracy", and/or "higher confidence"? Please explain.

B-Staff-59
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 1, p. 27 Figure 3-7.</u>

a) Is the high ratio of Canadian Westinghouse (CW) transformers with abnormal values primarily driven by vintages, manufacturing defects, both factors, or other factors? Please specify.

B-Staff-60
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 2, p. 17 Figure 1-2.

At the above noted reference, EPRI stated the following:

> Figure 1-2 shows the age demographics of the removed from service transformers from the period of 1981 to first quarter 2017.

a) Does Figure 1-2 show all transformers removed from service for all causes, including actual failures, imminent failures, and discretionary retirements such as preventative replacements, replacements to increase capacity, and all other causes?
   i. If no, please describe what is displayed in Figure 1-2.
b) Is Hydro One able to categorize replacements by all different causes over this period?
   i. If yes, please provide this categorization.
c) Hydro One's policies have historically not allowed for refurbishment investments to be made in transformers that have exceeded their expected service lives, even if the required refurbishments would be relatively low cost. Is that still Hydro One policy? For example, would a transformer operating beyond its expected service life qualify for replacement of leaking bushing gaskets, or replacement of worn tap changer components?

B-Staff-61
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 2, p. 18 Figure 1-3.

Ref: Exhibit B, Tab 1, Schedule 1, TSP Section 1.4, Attachment 2, Page 18 of 78

a) Figure 1-3 appears to show a lack of correlation between transformer age and likelihood of failure. Please explain these results.

B-Staff-62
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 2, p. 21, p.25 and Attachment 3, p. 21.

At the first reference above, EPRI stated the following:

> However, removed from service data is more abundant and consist of 419 transformers within a period of 1981 to first quarter 2017. The reasons for removal are not supplied in data, therefore failures and discretionary replacements cannot be distinguished. Since the reason is not supplied a time-to-event model can be developed where the event, rather than failure, is removal.

At the second reference above, EPRI stated the following:

> **Fitting the data to the Model**
> The removal rate model is verified by comparing the sample cumulative hazard function calculated from the actual event data (previously described) against the cumulative hazard functions created from the Weibull model. There are cumulative hazard functions for each MCMC observation. For each age from 0 to 100, we calculate the median cumulative hazard rate and the corresponding 95% credibility interval.

At the third reference above, EPRI stated the following:

> **Removed from Service Data**
> The removed from service data provided by Hydro One consists of 1218 circuit breakers as of third quarter 2017. No reason for removal was provided.

a) Please confirm that the term “removals” is not synonymous with the term “failures”.

b) Removals are being used to create a “hazard” curve, even though the reasons for the removals have not been categorized. Is this methodology appropriate as EPRI is applying it here?

c) A true "Hazard Rate" implies an age-related likelihood of failure. Please confirm that the supplied input data does not support the determination of a true Hazard Rate for these assets.

d) Based on the above references, it appears that EPRI has used uncategorized asset removal data in its derivation of Hazard Rates because that was the data set provided by Hydro One, rather than because the data is fit for purpose. Does the lack of categorization of retirement causes in the data supplied to EPRI potentially invalidate the conclusions drawn in the both the "Derivation of Circuit Breaker Hazard Functions" report and the "Derivation of Transmission Substation Transformer Hazard Functions" report?

B-Staff-63
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 4, p. 22.</u>

At the above noted reference, EPRI stated the following:

> **Conductor Condition Assessment Data**
> The Hydro One Conductor Condition Assessment Program defines an overall condition score of as equivalent to "end-of-life." Hydro One provided condition assessment data collected between January 2001 and December 2016.
>
> Investigators separated conductor assessment data by Overall Condition Score (OCS). Of the initial 404 conductor samples, 28 samples were assessed as OCS 5 from 21 different circuits and 61 samples were assessed as OCS 4 from an additional 29 different circuits. The remaining 315 samples were assessed as OCS 1 through 3.

a) Were the samples randomly gathered, or were they gathered from facilities with conductors previously identified as being near end of life? Please describe the sample gathering process applied.

B-Staff-64
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 4, p. 27.</u>

At the above noted reference, EPRI stated the following:

> **Correlation of Overall Condition with Age**
> The following three figures examine the relationships between overall condition and age; the third slide showing a histogram of conductor count by age between two overall condition groups (1-4 vs. 5). From these figures it may be observed that there is not a simple relationship between age and overall condition.

a) Would it not be more accurate to state that "there is not an *apparent* relationship between age and overall condition"? Most of the conductors around 100 years of age are all in condition 1 or 2.
b) Please confirm that the first chart in Figure 3-1 does not show a compelling age-related trend.
c) Does data scarcity outside of the core demographic distribution range potentially compromise the statistical confidence of any analysis drawing upon those outliers?

B-Staff-65
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 4, p. 29 and p. 32.</u>

At the first reference above, EPRI stated the following:

> **Extent and Severity of Rust**
> Figure 3-4 shows the extent of rust by age, as determined by visual inspection. Figure 3-5 shows severity of rust by age. From these two figures it may be observed that rust assessments do not appear to be reliable or useful assessment factors, possibly due to the subjective nature of visual inspection.

At the second reference above, EPRI stated the following:

> **Rust Assessments vs. Corrosion Zone**
> Investigators expected to see the best of rust ratings (e.g. 1, 2) skew towards corrosion zone C2 and C3, whereas the worst of the rust ratings (e.g. 5 or even 4) skew towards corrosion zone C5. However, such a pattern is not immediately apparent from the plots in Figure 3-10.

a) Were any of the conductor replacements in Hydro One's previous filing primarily driven by assumed age or location based corrosion issues?
b) Are any conductor replacements planned for the test period based upon assumed age or location based corrosion issues? If yes, please reconcile this justification against the referenced observations.

B-Staff-66
<u>Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 4, p. 95.</u>

At the above noted reference, EPRI stated the following:

> The conductor Condition Assessment (Score) data used are not from random samples. For the replacements data, it is unclear whether all replacements were due to failures or lines reaching condition(s) that warrant replacements or some other reasons. Analysis results from such data can potentially be pessimistic. However, the similarity between results based on condition assessment data and results based on replacements data lead one to believe that such a concern is not necessarily warranted, especially when the commonalities between the two data, sources in terms of time periods and circuits represented are limited (as discussed previously and shown in Figure 4-3).

a) Please confirm the following is an appropriate interpretation of the above paragraph:
   i. The data set is not representative of the general conductor population.
   ii. This assessment could lead to pessimistic results.
   iii. EPRI is not able to confirm whether or not the identified data deficiency is problematic.
b) Could the potential for pessimistic results identified in this statement drive excessive capital spending on conductor replacements?

B-Staff-67
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 11, p. 11.

At the above noted reference, EPRI stated the following:

> Hydro One removed a total of 87 polymer insulators for analysis. The samples were removed from lattice and from wood pole structures.
> It was recognized that locations with significant wetting or contamination would be the optimum environment from which the insulators should be removed. Based upon that, most of the insulators were removed from circuits in Southern Ontario.

a) Were these samples randomly selected, or chosen from locations with known insulator deterioration problems? Please provide details of the sample selection process.

B-Staff-68
Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 13, p. 30 and TSP/Section 2.1, pp. 36-37.

At the first reference above, Metsco stated the following:

> Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent.

At the second reference above, Hydro One stated the following:

> As part of its improved assessment process, Hydro One has introduced a new “flagging” process to account for special considerations and ensure stakeholder perspectives are consistently included in the evaluation of investments. Investment considerations that

cannot be quantified using the risk framework described above are captures by using qualitative flags to allow consideration of potential benefits of an investment beyond risk mitigation. To incorporate key customer and regulatory outcomes into its evaluation of projects, Hydro One's flags enable it to identify investments that address key customer priorities such as improving power quality, and investments that align to strategic priorities and objectives.

a) Given that asset management best practice is to quantify risk calculations in order to make "prioritization across individual assets, asset classes, or intervention options both simpler and more transparent", please explain why the use of non-mandatory flags is necessary and Hydro One is not able to achieve asset management best practice for each of the following flags:
    i. Customer Engagement
    ii. Productivity
    iii. Corrective Maintenance / Demand Replacements
    iv. Preventative Maintenance / System Renewals
    v. Strategic
    vi. Political Commitments
b) Given that asset management best practice is to make "prioritization across individual assets, asset classes, or intervention options both simpler and more transparent", for each of the non-mandatory flags please answer the following
    i. Why is a business case (or equivalent) not used to evaluate the application of a Customer Engagement flag? Please provide an example of the typical documentation supporting the application of a typical Customer Engagement flag.
    ii. Why is a business case (or equivalent) not used to evaluate the application of a Productivity flag? Please provide an example of the typical documentation supporting the application of a typical Productivity flag.
    iii. Please provide an example of the typical documentation justifying the application of a typical Strategic flag.
        1. In addition, please provide the process whereby codified goals by the leadership team or an explicit request by senior leadership is converted into investment spending outside of the standard Asset Management evaluation process.

2. In addition, how is the investment limit for the Hydro One leadership team determined for a Strategic flag?

iv. Why is a business case (or equivalent) not used to evaluate the application of a Customer Engagement flag? Please provide an example of the typical documentation supporting the application of a typical Political Commitments flag.

1. In addition, please provide the Hydro One governing the policy of a Hydro-One officer's power to make political commitments.

2. In addition, how is the investment limit for a Hydro One officer determined for a Political Commitments flag?

c) Is there any potential that projects where significant 'productivity' can be achieved may leapfrog projects that would otherwise be prioritized higher due to more urgent need or higher risk?

i. If yes, does that potentially subvert the intention of the asset management process?

ii. If yes, how does Hydro One mitigate this problem?

B-Staff-69

Ref: Exh B/Tab1/ Sch 1/TSP Section 1.4, Attachment 13, pp. 9-10 and TSP/Section 1.4, Attachment 13 p. 17.

At the first reference above, METSCO stated the following:

> With respect to the Reliability Risk Model, METSCO's finding is that the tool's analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed in the asset management. In making this observation, we note that a number of utilities do not or have not until recently attempted to formally forecast system reliability in a comprehensive manner. This contextual observation suggests that the RRM capability constitutes a bona fide continuous improvement step. Given that the RRM tool is currently used primarily as a customer communications tool to convey indicative changes to reliability risk levels across spend scenarios, the observed gaps in its technical parameters pose no meaningful risks from the asset planning perspective.
>
> Notwithstanding these findings, potential improvements to the RRM capability (or another reliability forecasting capability that Hydro One may choose to procure) that METSCO recommends in this report, would enhance its practical applicability and

> robustness, should Hydro One decide to integrate the tool as part of the asset management decision-making process more broadly.

At the second reference above with respect to Figure 1, METSCO stated the following:

> Our assessment of the Reliability Risk Model does not extend beyond this first level of assessment. The rationale for this decision is primarily grounded in the limited extent to which it is integrated Hydro One's asset management processes

a) Please confirm that Hydro One agrees with the statement that Hydro One's reliability analytic tool's "analytical underpinnings and functionalities trail advanced industry system reliability practices where these are deployed in the asset management".
b) Please confirm that Hydro One agrees with the statement that "the RRM tool is currently used primarily as a customer communications tool".
   i. If not, what it is primarily used for?
c) Please confirm that Hydro One agrees with the statement that enhancing Hydro One's "RRM capability … that METSCO recommends in this report, would enhance its practical applicability and robustness, should Hydro One decide to integrate the tool as part of the asset management decision-making process more broadly."
d) Please confirm that Hydro One agrees with the statement that the Reliability Risk Model is limited in the "extent to which it is integrated Hydro One's asset management processes"
e) What is Hydro One's plan (expressed in terms of scope, schedule and budget by year) to close the observed analytic tool gaps (i.e. RRM gaps) to enable incorporation of quantified expected system reliability outcomes into Hydro One's asset management decision-making processes?

B-Staff-70
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, pp. 25-26.</u>

At the above noted reference, METSCO stated the following:

> Recalling that one of the categories of our Level 1 assessment of these two capabilities is the degree of flexibility applied to analysis of various asset classes, our Level 2 assessment reviews the AA and ARA frameworks from the perspective of six major asset classes that undergo analysis by these two frameworks. These asset classes are:
>
> - Power Transformers
> - Circuit Breakers
> - Protection, Control & Telecom Infrastructure
> - Station Ancillary Equipment
> - Overhead Transmission Conductors
> - Underground Transmission Cables

a) Please confirm that Towers and Poles are included in the analysis performed within the AA and ARA frameworks.
   i. If so, why didn't METSCO evaluate the frameworks for these major asset classes?
   ii. If not, why doesn't Hydro One evaluate these major asset classes using the AA and ARA frameworks
   iii. Does Hydro One evaluate these classes outside of the AA and ARA frameworks?

B-Staff-71
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, pp. 25-26.</u>

At the above noted reference, METSCO stated the following:

> The outputs of the AA process are a Composite Risk Score and a framework of individual analytical parameter Risk Score Sub-Indices, ranging from zero (lowest risk) to 100 (highest risk). These scores are derived for each individual asset. The sub-indices represent the following assessment sub-categories:
>
> - Condition: considers the data on the physical state of assets and their core components along the relevant degradation factors expected to compromise the overall condition of an asset. Condition data used in the index development is sourced from field inspections, as well as Preventative Maintenance, Defect, and Trouble Call Reports, as relevant.
> - Demographics: Takes into consideration the assets' physical age in relation to its projected service life value or "Expected Service Life" (ESL), along with other demographic criteria like type, batch, manufacturer, etc. Hydro One defines asset ESL as the "average time duration in years that an asset can be expected to

operate under normal system conditions and is determined by considering manufacturer guidelines and Hydro One historical asset retirement data." The ESL criteria for particular asset classes were derived from the results of a 2014 Asset Failure Analysis study conducted by Foster Associates, in which asset class specific failure curves were validated using Hydro One's own historical failure data, and Iowa curve functions [3].

- Criticality: Takes into consideration the impact of failure at the individual asset, asset class, and station levels respectively. Input information for the formulation of this index includes factors like total customer load, voltage rating, critical customers and interconnections related to a given asset.
- Performance: Considers historical performance of a given asset, including the historical outage frequency and duration, as well as results from a Laplace trend test, which provide a measure of the difference in interval time between multiple forced outages.
- Utilization: provides the measure of asset deterioration related to the increased rate of asset utilization. Inputs such as the summer and winter peak loads, tap changer counter readings, and unit capacity data are used to formulate the index in this category for each asset.
- Economics: Takes into consideration the weighted average of emergency and corrective costs required to maintain the existing asset, as compared to the benchmark cost for the specific asset type/class.

Each of the AA evaluation category sub-indices, along with the overall composite score, contain references to "risk-based" calculations, incorporating parameters related to "probability" and/or "impact" of asset failure.

a) Please provide the source document for reference [3] above (i.e. R.E. White, "2014 Asset Failure Analysis", Foster Associates, 2014).
b) Please describe how the Risk Score Sub-Indices are used to calculate the Composite Risk Score.
c) For each of the assessment sub-categories, please define if the assessment sub-categories are used to inform the determination of Probability of Failure Only, Impact (i.e. Consequence) of Failure Only, Both Probability and Impact of Failure, or Neither Probability nor Impact (i.e. Consequence) of Failure.
d) For assessment sub-categories that are used to inform the determination of Probability of Failure, please define quantitatively how they work together to determine Probability of Failure.
e) For assessment sub-categories that are used to inform the determination of Consequence of Failure, please define quantitatively how they work together to determine Consequence of Failure.

f) Please define how Criticality is measured or otherwise determined for an asset failure.
g) Please confirm the range of Composite Risk Score for Power Transformers, Circuit Breakers, Protection, Control & Telecom Infrastructure, Station Ancillary Equipment, Overhead Transmission Conductors, Underground Transmission Cables, and if applicable, Towers and Poles.
h) Please confirm that a Risk Score Sub-Indices ranges from zero (lowest risk) to 100 (highest risk).

B-Staff-72
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, p. 29.</u>

At the above noted reference, METSCO stated the following:

> For clarity, METSCO understands that the RRM analysis only takes place after the AM decision-making processes – including the use of AA and ARA capabilities – has been completed.

a) Please confirm that the referenced statement is correct.
   i. If not, please define where the RRM analysis takes place in the AM decision making process, specifically where it takes place relative to the AA and ARA.

B-Staff-73
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, p. 30, p. 31, pp. 31-32 and p. 32.</u>

At the first reference above, METSCO stated the following:

> note that the definition of "risk" underlying this particular criterion of our assessment framework carries a particular meaning, consistent with the ISO 5500x asset management frameworks referenced in the criterion's definition.
>
> In this context, the notion "risk" entails a single quantifiable number that combines the quantitative expressions of probability (%) and impact of an asset's failure expressed in numerical terms (e.g. outage impact that may be expressed in monetary terms) as a multiplication between the two parameters. Such an expression of risk (or risk costs) is considered to be an asset management best practice since it captures both likelihood

and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent.

At the second reference above, METSCO stated the following:

While all of these risk-related factors are ultimately present in the expression of the final Composite Risk Score and individual Sub-Indices, at no point in the calculation process is risk explicitly expressed as Failure Probability × Failure Impact. Importantly, the fact that Hydro One's framework does not utilize the more commonly adopted expression of risk associated with leading technical standards, only implies than the manifestation of the relationship between the quantitative probability and impact related elements of the Hydro One AA approach is less clear and more complex (in light of the presence of multiple other factors in the calculation of the index) than it otherwise could be.

At the third reference above, METSCO stated the following:

the comparison of AA outputs – expressed as non-dollar indices – with the risk definitions established through other ARA inputs, is more complicated, and less intuitive than it could have been had all units were defined in numerical (preferably monetary) terms, as outcomes of Probability × Impact calculation. This representation of risk implies that the criteria comprising the assessment of asset failure Probability are clearly separated from the criteria comprising the Impact assessment if the asset failure occurs.

At the fourth reference above, METSCO stated the following:

Modest incremental adjustments to the AA framework to clearly define asset probability and impact would place the utility within the best practice utilities.

Based on our findings, METSCO provides the following recommendation:

- Consider clearly separating the risk factors/criteria in AA to define probability of failure of a specific asset, and the impact of asset failure to explicitly assess a broader variety of outage consequence costs, such as utility's and socioeconomic costs, including the costs associated with the environment, safety/collateral damages, environment, customer interruption costs and financial impacts.

a) Please confirm that the following METSCO statement is materially correct: *"the notion "risk" entails a single quantifiable number that combines the quantitative expressions of probability (%) and impact of an asset's failure expressed in numerical terms (e.g. outage impact that may be expressed in monetary terms) as a multiplication between the two parameters. Such an expression of risk (or* *risk costs) is considered to be an asset management best practice since it captures both likelihood and consequence of failure in a single numerical value – making prioritization across individual assets, asset classes, or intervention options both simpler and more transparent".*

   i. If not, why not.

b) Does Hydro One agree that its approach to defining risk "is more complicated, and less intuitive than it could have been"?

c) Does Hydro One intend to make the "Modest incremental adjustments to the AA framework to clearly define asset probability and impact would place the utility within the best practice utilities."

   i. If yes, please describe the plan (scope, schedule and budget) Hydro One will be implementing to adopt best practice.

d) Please quantify, in terms of standard deviations from Expected Direct Impact, where Worst Reasonable Direct Impact lies on the probability continuum between Expected Direct Impact and Worst Possible Direct Impact.

e) Please confirm that the probability of failure curves for Hydro One's assets are developed on an Expected Direct Impact basis (i.e. not a Worst Reasonable Direct Impact basis.

   i. If not confirmed, please describe the basis upon which the probability of failure curves are developed and how they relate to Worst Reasonable Direct Impact events.

   ii. If confirmed, please explain how Hydro One translates from an Expected Direct Impact probability curve to a Worst Reasonable Direct Impact probability curve.

   iii. If Hydro One does not translate between expected and worst reasonable probability curves, please explain how this avoids creating a systematic bias in evaluating risk.

B-Staff-74

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, p. 42.</u>

At the above noted reference, METSCO stated the following:

> The Criticality evaluation category assigns a criticality score to the evaluated power transformer based upon the station that it is installed within, the type of power

> transformer as well as the individual asset voltage rating, MVA rating and single point of vulnerability.

a) When evaluating transformer criticality, define the factors attributable to:
    i. The specific station
    ii. The type of power transformer
    iii. Asset voltage rating
    iv. Asset MVA rating
    v. Asset single point of vulnerability
b) For materially similar transformer capacity and voltage classes, please provide example risk assessments for the following representative transformer configurations:
    i. Transform feeding a radial circuit (i.e. non-redundant circuit)
    ii. Transformer feeding one circuit of a networked (e.g. redundant) transmission feed (i.e. one branch of a network/redundant supply)
    iii. The same transformer before and after a circuit was networked (i.e. risk evaluation before becoming networked, risk evaluation after becoming networked).
c) Repeat the above process for the following asset classes:
    i. Conductor
    ii. Breaker

B-Staff-75
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, pp. 44-45, Figure 7.

At the above noted reference, METSCO stated the following:

> Figure 7 illustrates an example of the incremental information captured in Hydro One's strategy document and collected as a part of ARA - in this case with respect to transformer oil leaks across the fleet. Oil leakage information represents a significant indicator of the overall degradation and failure of a power transformer. As such, while it is not captured in the AA score, this critical information is nevertheless integrated into the decision-making process prior to concluding asset prioritization work.

a) Are Major and Minor oil leaks an element of the condition assessment utilized in the AA process?
   i. If no, why doesn't the condition assessment for transformers include information that "represents a significant indicator of the overall degradation and failure of a power transformer"?
   ii. If yes, how does Hydro One avoid double counting the influence that oil leaks (major and minor) have on asset management decision making?

B-Staff-76
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, p. 45.

At the above noted reference, METSCO stated the following:

> These individual assessments provide an even greater granularity of information as to the current risks associated with individual asset, along with incremental justification of intervention. These information categories include:
>
> - Demographics: Age of the evaluated asset when compared to its ESL as well as overall demographics across all power transformers.

a) Do the demographics across all power transformers influence how Hydro One evaluates the risk score associated with an individual asset?
   i. If yes, please explain how.
b) Do the demographics across all power transformers influence how Hydro One evaluates the incremental justification of intervention?
   i. If yes, please explain how.

B-Staff-77
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, p. 47.

At the above noted reference, METSCO stated the following:

> The technical assessment document concludes with a net present value (NPV) analysis, where different options (e.g. status quo, repair/refurbish, replacement) are compared and contrasted with each other, using the annual investment requirements as an input for each investment option in order to identify the preferred option that yields the lowest NPV result.

a) Please provide at least two typical technical assessment documents for each of the following asset classes:
   i. Transformers
   ii. Breakers
   iii. Conductor

B-Staff-78
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13.

Throughout its report, METSCO provides recommendations to Hydro One for improving its asset management practices.

a) In a tabular format listing all the recommendations and suggestions provided by METSCO, please specify if and how Hydro One will implement the recommendations, and the timeframes within which the recommendations will be implemented.

B-Staff-79
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 13, pp. 76-78.

At the above noted reference, METSCO provided overall recommendations and risk results for ABC TS (Figure 27)

a) Please provide the original Hydro One Risk Assessment that informed the results shown in Figure 27 of the METSCO report.

B-Staff-80
Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 14, p. 28.

At the above noted reference, BCG stated the following:

> In developing projects, best practice is to evaluate among different types of potential options to ensure asset life cycle costs are optimized. Hydro One conducts this analysis as it is developing projects, with a focus on stations assets given the lack of maintenance or refurbishment alternatives for lines assets. Hydro One conducts a combination of qualitative and quantitative analysis to evaluate among different capital spending options and among capital and OM&A options. For transformers, NPV models

are used to assess capital vs. OM&A tradeoffs, while for other types of stations assets, qualitative analysis is conducted to evaluate the risks and benefits of different capital and OM&A scenarios

a) Please provide typical documentation for capital versus OM&A tradeoff analysis for the following asset classes:
   i. Power Transformers
   ii. Circuit Breakers
   iii. Protection, Control & Telecom Infrastructure
   iv. Overhead Transmission Conductors

B-Staff-81

Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 14, Exhibits 23, 24, 25 and 27.

a) Based on Exhibits 23, 22, 25 and 27 referenced above, it appears that all steps of Hydro One's asset management and investment planning process are documented. For all of the investment planning projects (or at least the major asset classes of Power Transformers, Circuit Breakers, Protections, Overhead Transmission Conductors), please provide a table (preferably in MS Excel format) listing the following:
   i. Project Identifier
   ii. Project Name
   iii. Asset Class
   iv. Project Cost
   v. Risk: For each of the three risk categories (Safety, Environmental, Reliability) before and after each of the relevant asset management steps where these values change (e.g. Candidate Investment Development, Scoring, Calibration, Initial Prioritization, Challenge Sessions, Executive Review etc.)
      1. Baseline Probability of Failure
      2. Baseline Consequence of Failure
      3. Baseline Risk
      4. Mitigated Probability of Failure
      5. Mitigated Consequence of Failure

6. Mitigated Risk (Residual Risk)
7. Mitigated Risk Units

vi. Project cost

vii. Primary Project Driver

viii. Flags before and after each of the relevant asset management steps where these values change (e.g. Candidate Investment Development, Scoring, Calibration, Initial Prioritization, Challenge Sessions, Executive Review, etc.)

B-Staff-82

Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 15, p. 2.

At the above noted reference, Hydro One stated the following:

> **Investment Development**
> Hydro One's transmission assets are replaced as condition warrants through rigorous testing. However, a backlog of asset condition testing has developed for assets such as conductors and shieldwire, where a large portion of the asset base is approaching it's Expected Service Life ("ESL").

a) The EPRI report "Derivation of Overhead Conductor Hazard Function" (Exhibit B-1-1 Attachment 4) states on page 3-30 "Even with these more homogeneous (though smaller) data subsets, Age does not appear to have a significant correlation with overall condition or any of the constituent conditions (assessment factors)." and on page 3-41 "The investigations focusing on smaller and more homogeneous data sets revealed no clear correlations between overall condition and age, similar to the findings for the larger data set." Please confirm that conductor demographics are not driving the urgency of the expanded conductor replacement program.

b) Has new information been obtained since Hydro One's most recent prior cost of service application that justifies significantly increased annual conductor replacement expenditures?

B-Staff-83

Ref: Exh B/Tab1/Sch 1/TSP Section 1.4, Attachment 15, p. 5, Figure 2 and Section 3.3, p. 4.

At the second reference above, Hydro One stated the following:

> System Renewal investments will increase 5.5% over the course of this TSP, with investment in both stations and line refurbishment seeing a 5.7%, and 5.5% increase over the plan, respectively. The objective over the planning period is to return to top quartile reliability performance and this level of spending is designed to accomplish this objective.

a) How were the reliability performance targets shown in Figure 2 selected?
b) How was the top quartile performance target determined? Is this an internal Hydro One target or was this target set by others?
    i. If the target is set by others, were they aware at the time that such a large capital spending increase would be necessary to meet the performance target?
c) What is the basis for confidence that the proposed spending is necessary to deliver the target performance levels? In other words, how was the performance outcome calculated based upon the proposed spending levels?
d) Given that cost concerns are the biggest issue for most ratepayers, how did Hydro One determine that a top quartile performance target is appropriate for such a large system covering such a range of load densities, geographies and climatic regions?

B-Staff-84

Ref: Exhibit B-1-1 / TSP Section 1.5/ Figure 1- Evolved Electricity Transmitter Scorecard & Targets- Hydro One Networks Inc.& EB-2016-0160/Exh B2/Tab 1/Sch 1/Table 2

In the previously proposed transmission scorecard, which is the second reference above, under Cost Control, Sustainment Capital was made up of seven Tier 3 Metrics, two of which are Line Clearing Cost per km and Brush Control Cost per Ha.

a) Have the other five metrics been removed or incorporated elsewhere?

B-Staff-85
Ref: Exh B/Tab1/Sch 1/TSP Section 2.2, p. 11, Figure 5, p. 12, Figure 6 and p. 13, Table 4.

a) Please confirm that both the forced outage duration (Figure 5) and forced outage frequency (Figure 6) has been declining over the same period that annual asset failure rates (Table 4) have been increasing.
b) Please explain this inverse correlation.
c) If redundancy is improving system reliability, are asset level risk evaluations being adjusted to account for the increasing redundancy?

B-Staff-86
Ref: Exh B/Tab1/Sch 1/TSP Section 3.0, p. 4, Figure 1.

a) Please provide the before and after risk scores for each of the 4 projects identified in Figure 1.
b) Please provide the before and after risk scores for each alternative considered for the 4 projects.
c) Given that the 4 projects identified in Figure 1 are starting with significantly different risk scores, please explain why they all made the priority project list.
d) Are there projects included in this filing for which the existing candidate investment scoring is in any of the green zones? If yes, please identify these projects.
e) Please provide a concrete example of the change in risk score for an asset located in a radial system that becomes redundant or networked. For example, please show before and after risk scores for a transformer that was initially in a radial installation that was later modified to become a redundant or networked installation.

B-Staff-87

Ref: (1) Exh B/Tab1/Sch 1/TSP Section 3.0, p. 5,
(2) TSP Section 3.1, p. 1,
(3) TSP Section 3.2, p. 2
(4) TSP Section 1.3, p. 8.

At the first reference above, Hydro One stated the following:

> Overall spend: Hydro One's proposed budget envelope was set at a level below what was tested with customers, as evidenced in Sections 1.3 and 3.2 of this TSP. Hydro One agreed with customer feedback that this approach offered the appropriate balance between ratepayer costs and risk mitigation.

At the second reference above, Hydro One stated the following:

> The proposed plan balances: (i) asset-related needs of the transmission system arising from age, condition and environmental and regulatory compliance requirements; (ii) customer needs and preferences relating to reliability; (iii) regional infrastructure and broader system needs to address system constraints, enable new load growth, and facilitate access and new connections to the transmission system; and (iv) impact on customer rates.

At the third reference above, Hydro One stated the following:

> All business customer segments, particularly LDCs, prefer that investments be spread out over time, along with stable rate increases. This preference is due primarily to perceived affordability for ratepayers and the ability to plan ahead.

At the fourth reference above, Hydro One stated the following:

> Cost was also raised at various times throughout the survey. The desire for good reliability at a competitive or low cost was universal.

a) Customers have consistently expressed that cost is their #1 concern (i.e. the desire for low cost was universal), yet Hydro One is proposing a 40% increase in capital spending in a low inflation environment with negative system load growth and good reliability performance. In this context, please explain how Hydro One's plan properly balances the 4 points listed above.
b) Did customers endorse a 40% increase in capital spending? Please provide evidence.
c) Regarding the pacing of investments (per the third reference above):

i. Do customers demand stable rate increases, or would they be happier with flat or decreasing rates? Please provide evidence supporting this claim.
ii. Is it more appropriate for this statement to read as: "Customers prefer that any unavoidable rate increases are at least stable"?
iii. How has this customer demand been considered when developing Hydro One's proposed 40% capital spending increase?

B-Staff-88

Ref: (1) Exh B/Tab1/Sch 1/TSP Section 3.1, p. 6, Figure 2,
(2) TSP Section 3.1, p. 8,
(3) TSP Section 3.1, p. 11.

At the first reference above with respect to Figure 2, Hydro One stated the following:

> Without the proposed renewal investment, the following percentages of major stations and lines assets are expected to reach the end of ESL by 2024: 41% of protections assets, 39% of transformers, 23% of breakers, and 13% of lines (conductors) assets.

At the second reference above, Hydro One stated the following:

> **3.1.1.1 Stations Renewal**
> The TSP includes stations renewal investments of $3.5 billion (53% of the total planning period forecast) to address transformers, circuit breakers, and protection, control and telecom equipment that are deteriorated as determined by condition assessments. Replacement is paced to maintain (though not lower) the proportion of assets beyond ESL over the planning period. Without the proposed investment, the proportion of assets beyond ESL will increase significantly, as set out in Figure 2.

At the third reference above, Hydro One stated the following:

> **3.1.1.1.1 Transformers**
> Hydro One plans to manage this risk by replacing an average of 22 transformers annually from 2020 to 2024 selected based on condition. With this replacement rate, Hydro One would be able to maintain the number of units that are beyond ESL to approximately the same level as of 2018, through to the end of 2029.

a) Is Figure 2 being used to justify the proposed increase in renewal spending?
b) Per the EPRI findings, please confirm that conductor ESL should be 90 years rather than 70 years.

c) Per the EPRI findings, please confirm that high and low pressure underground cable ESL should be 70 years rather than 50 years.
d) Given the recent large ESL step changes in the conductor and underground cable categories, please confirm that ESL is not an accurate indicator to justify asset replacements.
    i. Is Hydro One using ESL as a justification for spending in the above referenced excerpts?
e) Please confirm that all assets in a particular age class do not degrade at the same rate, and that some assets will survive far beyond expected ESL in excellent or good condition.

B-Staff-89
Ref: Exh B/Tab1/Sch 1/TSP Section 3.1, p. 11.

At the above noted reference, Hydro One stated the following:

> **Transformers**
> Transformers are critical components used in electric power systems to convert power from one voltage level to another to facilitate supply to local distribution companies and industrial customers. Transformer forced outages have been a major cause of customer delivery point interruptions over the past 10 years, representing 13% of equipment caused events on Hydro One's transmission system. Through asset condition assessment, 17% of Hydro One's transformer fleet are rated high or very high risk based on oil testing results. Currently, 25% of Hydro One's transformer population is beyond its ESL. Assuming no replacements are undertaken, Hydro One anticipates that 280 units (39% of the transformer population) will exceed their ESL by 2024, and 332 units (46% of the population) will exceed their ESL by 2029.

a) Are "customer delivery point interruptions" and "events" used as synonymous terms in this explanation?
b) What percentage of events on Hydro One's system are directly caused by transformer failures?
c) How many customer delivery point interruptions were directly caused by transformer failures over the 10 year period?
d) What percentage of the "beyond ESL" transformers would be expected to fail between 2020 and 2024 based on past failure trends if they are not replaced?

e) Please confirm that the anticipated failure rate provided in answer d) above is not the same as the removal rate parameter derived in the EPRI transformer report (called a Hazard Rate in that report, although derived utilizing only uncategorized transformer removals data)
    i. If not confirmed, please explain why Hydro One is unable to provide an expected transformer failure rate.

B-Staff-90
Ref: Exh B/Tab1/Sch 1/TSP Section 3.1, p. 12 and TSP Section 1.1, p. 48.

At the first reference above, Hydro One stated the following:

> In response to these risks, Hydro One will invest $594 million over the five year TSP period to replace 95 ABCBs and remove their associated high-pressure air systems (see ISD-SR-01).

At the second reference above, Hydro One stated the following:

> **System Renewal**
> Hydro One's TSP reflects the need for continued station renewal investments at a cost of $3.5 billion, or approximately 53% of the total planned capital expenditures over the planning period, to address deteriorated station assets including transformers, circuit breakers, protection, control and telecom equipment. These replacements are expected to approximately maintain the proportion of transformers on the system that are beyond their expected service life at 26%, approximately maintain the proportion of protection systems operating beyond their expected service life at 28% and maintain the number of breakers that are beyond their expected service life at 12%. This includes the replacement of 72% of the air-blast circuit breakers (ABCBs) at a cost of $594M. ABCBs are about 10 times more expensive to maintain and about 4 times less reliable than their equivalent SF6 circuit breakers.

a) Please confirm that this implies an average cost of $6 million per breaker replacement. If not confirmed, please explain.
b) What is the present total annual cost of ABCB maintenance?
c) How many ABCBs receive maintenance attention on average each year?
d) If the planned ABCB replacements are implemented, what are the expected annual O&M cost savings and how will those savings be realized to the benefit of ratepayers? Please provide a detailed explanation of and proportional contribution to savings of each savings source (e.g. workforce reduction and/or re-allocation, fewer contractor hours, reduced consumables, etc.).

B-Staff-91
Ref: Exh B/Tab1/Sch 1/TSP Section 3.1, pp. 11-12.

At the first reference above, Hydro One stated the following:

> **Circuit Breakers**
> A circuit breaker is a mechanical switching device that is capable of carrying and interrupting electrical current under normal and abnormal conditions. During abnormal conditions, breakers operate rapidly to interrupt high currents and minimize impact on the rest of the power system. Hydro One's circuit breaker fleet includes 549 units that are currently beyond their ESL. Breakers have been a significant contributor to customer delivery point interruptions over the past 10 years, representing 13% of these equipment caused events. Projections for the number of breakers operating beyond ESL by 2024 and 2029, in the absence of replacements or failures, are 1,088 and 1,766, respectively.

a) Are "customer delivery point interruptions" and "events" used as synonymous terms in this explanation?
b) What percentage of events on Hydro One's system are directly caused by breaker failures?
c) How many customer delivery point interruptions were directly caused by breaker failures over the 10 year period?

B-Staff-92
Ref: Exh B/Tab1/Sch 1/TSP Section 3.1, p. 13.

At the above noted reference, Hydro One stated the following:

> **Lines Renewal**
> Given that a significant portion of Hydro One's transmission lines were built in the 1950s, they will reach the end of their ESL of 90 years in the next two decades. Detailed condition assessments are being conducted for lines exceeding 50 years of age to inform line refurbishment program development. The planned circuit-kilometres of conductor to be replaced in the TSP have been confirmed to be at end of life through condition assessment. While the planned rate of refurbishment does not keep up with the aging lines demographics, risk is being managed by prioritizing line refurbishment investments based on detailed asset condition assessments, which account for the fact that the deterioration rate of transmission line assets depends on location, environmental and system conditions.

a) What proportion of Hydro One transmission lines is presently beyond ESL?

b) What proportion of Hydro One transmission lines will be beyond ESL in 2024 if the lines replacements proposed in this TSP are executed?
c) Given that a significant portion of Hydro One's transmission lines were built in the 1950s, does this mean that the specified "significant portion" of Hydro One's transmission lines are presently 20 or more years younger than ESL? In other words, do those conductors have an expected remaining service life of 20 years or more?
d) Please confirm that transmission conductors installed after 1930 have not yet reached ESL.
e) Were the conductors proposed for replacement in this TSP all installed before 1930?
f) Please explain any discrepancy between the proposed conductor replacement projects and the expected remaining useful service lives of the conductors proposed for replacement based on ESL.

B-Staff-93
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.1, p. 16 and TSP Section 1.1, p. 43.</u>

At the first reference above, Hydro One stated the following:

> Hydro One operates a condition assessment program that focuses on conductors beyond 50 years of age. Condition assessment results indicate that 13% of the conductor fleet is at high risk. Despite a planned increased level of replacements when compared to historical levels, the number of conductors beyond the ESL of 90 years is still increasing. An overhead conductor failure can have severe reliability and safety consequences. If this issue is not addressed in a proactive and timely manner, system and customer reliability as well as safety will be placed at risk. Consequently, an increase in planned replacements – even though it will not completely stop or reverse the trend in line demographics – is required to maintain acceptable fleet condition and performance and to avoid a sudden spike in future investments that would otherwise be required as a result of deferred replacements.

At the second reference above, Hydro One stated the following:

> **Lines Asset Management**
> Hydro One's approach to asset management for its transmission line assets is shaped by the nature of the specific line assets and their typical service lives. In particular, transmission conductors have an expected service life of 90 years. When a conductor fails or based on its condition, as confirmed by testing, has been determined to have reached end of life, replacement is the only solution.

a) How common are system events caused by overhead conductor failures? To be more specific, what percentage of Hydro One customer delivery point interruptions are directly caused by spontaneous condition-related conductor failures?
b) How many such events occur each year?
c) Please confirm that the stated percentages and event counts in Hydro One's response to parts a) and b) do not include conductor failures caused by external factors such as tree falls, vehicle contacts, lightning strikes, tornadoes/extreme wind fronts or extreme snow/ice loads that exceed design loads.
d) Please provide a list of the most common conductor-related failure modes experienced by Hydro One (e.g. sagging into objects during hot weather power loads, heavy snow loads or heavy ice loads, blowing into other objects under extreme wind loads, phase to phase contacts under galloping conditions, splice/sleeve failures, dead end/termination compression hardware failures, etc.).
e) Please provide an associated percentage of conductor failures per mode identified in part d).
f) Please distinguish between conductor life and risk of failure versus sleeve (splice) or compression dead end failure.

B-Staff-94
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.2, pp. 10-11, Table 2 and TSP Section 1.2, Attachment 1, p. 2.</u>

At the first reference above, Hydro One stated that “The material TSP investments identified through Regional Planning are listed in Table 2…”

At the second reference above, the IESO stated the following:

> During the second cycle of regional planning, the Regional Planning Study Team is giving greater consideration to assets reaching end of life. More specifically, they are considering opportunities to “right size” equipment, the potential reliability impact of the longer-term outages required to carry out significant replacement projects, and the potential to optimize the system design as part of the scope of the asset replacement.

a) Please explain why most of the “material TSP investments identified through Regional Planning” are categorized as System Renewal Projects as opposed to System Access and System Service projects.
b) Please confirm that all of the listed SR projects were initially identified as replacement candidates by Hydro One's asset management processes and subsequently brought into the regional planning processes by Hydro One in the context of being projects that would be happening regardless of any regional planning requirements, and that the Regional Planning participants were invited to propose customization or optimization of the identified replacement projects to better address regional planning needs.
    i. If confirmed, is it possible that the regional planning process might have selected a different solution for at least some situations if Hydro One had not offered the replacement projects as already being “fait accompli”?
    ii. If not confirmed, please explain how the SR projects were identified through the Regional Planning processes.
c) Is the IESO involved in determining if Hydro One's assets have reached end of life, or is this solely determined by Hydro One?
d) How are the "end of life" assets introduced into the regional planning process?
e) Is the focus of the regional planning groups limited to providing directional input to Hydro One (e.g.: if you are going to replace a specific asset anyway, consider these system needs when selecting a replacement option)?
f) How is cost sharing between benefiting parties determined when the triggering driver for a regional planning project is end of life asset condition?
g) Does the same answer hold true if the regional planning group determines that it is necessary to upgrade beyond like-for-like replacement, with an associated greater project cost?

B-Staff-95
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.2, p. 13.</u>

At the above noted reference, Hydro One stated the following:

> **3.2.4.2 Derivation of Transformer Hazard Functions**
> This study confirmed that Hydro One’s pacing approach to the replacement of transformers is appropriate.

> **3.2.4.3 Derivation of Circuit Breaker Hazard Function**
> This study was performed by EPRI and describes EPRI's efforts to (i) model and develop circuit breaker removal rates from historical replacement records and (ii) apply them to forecast the number of circuit breakers expected to require replacement based on past practices. EPRI has developed a methodology using advanced statistical techniques for analyzing circuit breaker historical removals and applied it to the Hydro One's circuit breaker fleet. Using Hydro One's circuit breaker retirement data, EPRI modeled Hydro One's circuit breaker removals and has forecast probable future removal rates. The study confirmed that Hydro One is replacing younger circuit breakers at a rate expected from the statistical model.

a) Please confirm that EPRI actually derived a transformer "removal rate" function, utilizing the uncategorized transformer removal data provided by Hydro One.
b) Please confirm that EPRI actually derived a breaker "removal rate" function, utilizing the uncategorized breaker removal data provided by Hydro One.
c) Please explain how the conclusions in 3.2.4.2 and 3.2.4.3 can be considered as accurate given that they are based on uncategorized asset removal data.

B-Staff-96
Ref: Exh B/Tab1/Sch 1/TSP Section 3.2, p. 25.

At the above noted reference, Hydro One stated the following:

> Hydro One's average frequency of sustained delivering point interruptions (T-SAIFI-S) performance over the past five years was 0.63 per delivery point, and the performance trend is indicating an increase in the average number of sustained interruptions per delivery point.

a) How steep is the performance degradation trend mentioned above?
b) Is the performance degradation trend slope greater than 1 standard deviation from the mean?
c) Is this problem sufficiently urgent to justify a 40% capital spending increase?

B-Staff-97
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, pp. 6-7.

At the above noted reference, Hydro One discussed system renewal investments.

a) Regarding the overspend in 2015 and 2016, were the overspent amounts within Hydro One’s expected +/- cost range for this project?
b) Did the “increased spending on emergency replacements and spare transformer purchases” in 2015 lower spending requirements in later years?
    i. If not, why not?
c) Please explain how “the complexity of the required environmental assessments and public consultation” resulted in a $15 million reduction in spending? Did this underspend fall within Hydro One’s expected +/- cost range for this project?

B-Staff-98
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: GP-01, p. 5.</u>

At the above noted reference, Hydro One stated the following:

> In Hydro One’s previous OEB rate filing applications, this ISOC investment was planned for a dual primary control and monitoring configuration, but to realize better operating synergies, it was decided that a single primary configuration will deliver more benefits. The updated plan involves making the ISOC Hydro One’s primary control centre once it is fully in-service so that the deficiencies at the OGCC will be remedied without impact on real-time operations. The OGCC will then be re-designated as the backup centre. The existing BUCC will then be decommissioned. Incremental costs associated with this updated plan will only be from employee relocation considerations. This amount is forecast to be between $1 million to $3 million. The relocation cost will be budgeted as a one-time OM&A charge, and it is not included in this Investment Summary Document costing.

a) When was the current Ontario Grid Control Centre (OGCC) constructed?
b) What was the actual all-in cost of the OGCC when constructed?
c) What is the total remaining undepreciated OGCC rate base?
d) What uncertainties are driving the $1 million to $3 million OM&A charge cost range and what is the basis for this charge?

B-Staff-99
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: GP-01, p. 17.</u>

At the above noted reference, Hydro One stated the following:

> The exclusion of the SOC was rejected, because it fails to maximize financial performance through synergistic lines of business occupancy and maximize use of shared critical infrastructure. Bringing SOC services to the ISOC will reduce security monitoring service OM&A cost by approximately $0.6M on an annual basis. This SOC exclusion also fails to leverage operational effectiveness synergies for operational

> response to security threats, both physical and cyber. By co-locating physical security monitoring (i.e. SOC) with the other lines of business, opportunities for collaboration on physical risk mitigation will be optimized.

a) Does the proposed arrangement increase the probability of common mode failure of multiple lines of Hydro One business responsibility due to lack of space diversity? If no, please explain why not.
b) Please explain the meaning of the phrase "it fails to maximize financial performance through synergistic lines of business occupancy".

B-Staff-100
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: GP-02, p. 2.</u>

At the above noted reference, Hydro One stated the following:

> 2. Telecom circuits have migrated from older point to point connections to modern IP based routable circuits. These newer circuits do not have the same geographic limitations.

a) Does migration from “point to point” to “IP based routable circuits” increase the Integrated System Operating Centre (ISOC) exposure to malicious software attacks?
   ii. If yes, please quantify the increased exposure.
   iii. If no, explain why not.

B-Staff-101
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-02, p. 1.</u>

a) The priority of SR-02 Station Reinvestment Projects, as well as many other projects identified in this filing, is identified as "Medium". Will Hydro One have any outstanding "High" priority projects at the end of the test period?
   i. If yes, please explain why Hydro One is proposing to execute Medium priority projects prior to completing all outstanding High priority projects.

ii. If yes, does this indicate need for refinement/recalibration of Hydro One's project prioritization methodology, mischaracterization of project priorities, inability to deliver all High priority projects during the test period, or something else? Please explain.

B-Staff-102
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-02, p. 7.

At the above noted reference, Hydro One stated the following:

> **C. EXPENDITURE PLAN**
> As discussed above, this investment is needed to replace various bulk power and load supply station assets that have reached their expected service life (“ESL”) and are in deteriorated condition, which may lead to unexpected failures. Hydro One planned this investment to achieve completion as effectively and efficiently as possible.

a) Are any of the stations in this program being rebuilt because major components have reached ESL?

B-Staff-103
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-02, p. 9, Table 2.

a) Please indicate which of the listed station projects are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. NERC/NPCC requirements;
   ii. Environmental work;
   iii. In situ replacement.

B-Staff-104
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-02, pp. 11-12.

At the above noted reference, Hydro One stated the following:

Alternative 2: Planned Replacement of Components (Unbundled) involves replacing individual station components in high risk and deteriorated condition on a sequential basis as each component reaches its end of useful service life. This alternative is viable only when single components at a transmission station are deteriorated. Unlike reactive replacements, planned replacements have the advantage of minimizing system and equipment outages through coordinated outage plans. However, this alternative is not efficient when multiple components at a transmission station are in deteriorated condition or operational concerns exist with respect to these components. Since a component based planned replacement strategy would only replace assets as they come to end of life, Hydro One would not realize any efficiency during execution of the design, construction, and commissioning stages of the work that a station-centric, bundled replacement strategy offers. Furthermore, this alternative does not offer any opportunities to reconfigure the physical or electrical layout of the station in order to minimize future maintenance requirements or to eliminate any existing operational concerns.

a) Please quantify the total loss of useful service life by asset for all assets being retired prior to end of life in each of the cited station projects.
b) Please quantify (in monetary terms) the offsetting efficiency gain used by Hydro One to justify early retirement of the assets being retired in each of these projects that will not have reached end of life when it is retired.

B-Staff-105

Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-03, p. 2.

At the above noted reference, Hydro One stated the following:

> The Project pacing has been influenced by bulk transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Is exceeding ESL the primary driver or an important factor driving any of the transformer replacements identified in this program?
   i. If yes, please identify those replacements.
   ii. If no, please identify the primary driver for each proposed replacement.

B-Staff-106
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-04, p. 2.

At the above noted reference, Hydro One stated the following:

> The Projects pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's bulk station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Projects.

a) Please quantify the increased system reliability risk that would be associated with not making the proposed investments during the test period.

B-Staff-107
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-04, p. 7, Figure 2 and p. 9, Table 9.

a) The demographic trend in Figure 2 appears to indicate a relatively slow increase in the cumulative total number of breakers operating beyond ESL if no additional breakers are replaced during the test period. Please explain the pacing of the investments shown in Table 1 in the context of the demographic trend shown in Figure 2 above.
b) How many forecast years are included in the "Forecast 2025+" column in Table 1?
c) Do the values listed in the "Forecast 2025+" column in Table 1 represent the average annual spend or cumulative total spend for the Forecast period? Please explain.
d) How many historical years are included in Table 1's "Prev. Years" column?
e) Do the values listed in the "Prev. Years" column represent the average annual spend or the cumulative total spend of the historical period? Please explain.
f) Do the assumptions noted in responses b) through e) apply to all ISDs included in this filing?

B-Staff-108

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-04, p. 10, Figure 2 and p. 9, Table 2.</u>

a) Please indicate which of the listed projects in Table 2 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. Ministry of the Environment, Conservation and Parks requirements;
   ii. NERC requirements;
   iii. NPCC Requirements;

b) Which projects are new location installations and which are in-situ installations?

B-Staff-109

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-05, p. 2.</u>

At the above noted reference, Hydro One stated the following:

> The Project pacing has been influenced by load supply transformer fleet demographics, observed condition, anticipated condition, and performance factors as well as environmental and safety concerns, as described below. Based on Hydro One's overall transformer demographic profile, it is forecasted that an increasing number of units will age beyond Expected Service Life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases supply reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Please quantify the potential impact upon supply reliability if the transformers (and associated equipment) proposed for replacement in this program are not replaced during the test period.

B-Staff-110

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-05, pp. 10-11, Table 3.</u>

a) Please identify which of the listed transformer replacement projects in Table 3 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
   i. Ministry of the Environment, Conservation and Parks requirements;
   ii. PCB compliance requirements;

b) Which transformer replacement projects in Table 3 are new location installations and which are in-situ installations?

B-Staff-111
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-06, p. 2.

At the above noted reference, Hydro One stated the following:

> The Project pacing has been influenced by the assessment of equipment condition and in consideration of operational effectiveness, customer preferences, and safety concerns. Based on Hydro One's load supply station breaker demographic profile, it is forecasted an increasing number of units will age beyond expected service life ("ESL") within the next five years. Operating a large percentage of the fleet beyond ESL increases system reliability risk as this equipment tends to have a higher probability of failure. Consequently, Hydro One plans to manage this anticipated risk by undertaking the Project.

a) Please quantify the potential impact upon system reliability if the load station and ancillary equipment proposed for replacement in this program are not replaced during the test period.

B-Staff-112
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-06, p. 11, Table 2.

a) Please identify which of the listed projects in Table 2 are potentially subject to increased costs due to each of following factors, and quantify the expected project cost increase due to each factor:
    i. Ministry of the Environment, Conservation and Parks requirements;
    ii. NERC requirements;
    iii. NPCC Requirements;
    iv. PCB compliance requirements;
b) Which projects are new location installations, and which are in-situ installations?

B-Staff-113
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-13, p. 1 and p. 3.

At the first reference above, Hydro One stated the following:

> Hydro One has been phasing out ADSS fibre optic cables from its asset base due to high risks to reliability and safety. The remaining sections of ADSS fibre cable have deteriorated significantly over the recent years. Excessive premature wear and tear has compromised the asset and hence Hydro One's ability to operate the transmission system reliably. In order to maintain the reliability of the transmission system, there is a need to replace remaining sections of Hydro One owned ADSS fibre optic cable.

At the second reference above, Hydro One stated the following:

> The Expected Service Life (ESL) of fibre optic cable is based on the type of cable. The manufacturers' recommended ESL for OPGW is 40 years and 25 years for ADSS. Historical performance shows that the mechanical aspects of the fibre cable can prematurely reduce the cable's life span. In the case of ADSS cables, unusual mechanical stresses have resulted in high rate of premature failures before its ESL expired. ESL is now lowered to 15 years and it is used to trigger the asset condition assessment in the replacement decision making process.

a) What is causing the premature wear and tear of the ADSS fibre cable? Was the ADSS incorrectly specified, was it incorrectly designed and installed, were there manufacturing defects or type faults, or other? Please list all reasons that apply and explain.
b) What is the reason for the unusual mechanical stresses?
c) Will Hydro One have any remaining ADSS when this program has been completed?

B-Staff-114
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 1 and ISD: SR-20, p. 1.</u>

At the first reference above, Hydro One stated the following:

> **A. OVERVIEW**
> This set of Transmission Line Refurbishment Projects involve the replacement of all End- Of-Life ("EOL") components along all or part of a line section. These projects are driven by the need to replace major transmission line components, verified to be at EOL by condition assessment, including Aluminum Conductor Steel Reinforced ("ACSR") conductor, obsolete copper conductor, or deteriorated structures in high risk condition.

At the second reference above, Hydro One stated the following:

> **A. OVERVIEW**
> Near End-of-Life Transmission Line Refurbishment Projects (the "Projects") involves the proactive replacement of the Aluminum Conductor Steel Reinforced ("ACSR") conductors that are confirmed, through condition assessments, to be in a deteriorated condition and approaching End-Of-Life ("EOL"). The near EOL conductors are assets whose condition is expected to be in a state requiring removal from service in the near

> future. Over the test period, there is large population of overhead ACSR conductor that will reach or exceed their Expected Service Life ("ESL") and therefore the probability of their failure is increasing as a result of their aggregate increase in deteriorated condition.

a) Is conductor condition the primary driver for all of the projects included in both the SR-19 and SR-20 programs?
    i. If no, please identify all projects in these programs with a different primary driver (other than conductor condition), list the primary driver associated for each project, and explain why these projects are included in this program.
b) Please confirm that all conductors and/or all structures throughout the length of the identified segments have been verified to be at end of life.
    i. If not confirmed, please identify what percentage of the conductor and/or percentage of structures in the identified segments have been confirmed to be at end of life.

B-Staff-115

<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 1 and p. 7.</u>

At the first reference above, Hydro One stated the following:

> Hydro One has evaluated various alternatives for these Projects, as described below, and concluded that replacing the EOL deteriorated ACSR, obsolete copper conductors, or refurbishing deteriorated structures is the most cost effective and efficient undertaking for sustaining these assets.

At the second reference above, Hydro One stated the following:

> Presently, the Hydro One overhead transmission system has 3,680 km of conductor known to be in high risk condition, as verified empirically through condition assessment.

a) What is the predicted conductor-driven probability of failure of each of the lines with ACSR conductor in this program if those lines are not rebuilt during the test period?
b) Please clarify whether there are 3,680 km of conductor or 3,680 circuit-km known to be in high risk condition.

c) Of the 3,680 km of conductor "known to be in high risk condition", what is the probability of conductor system failure per km during the test period?
    i. What is the basis for the claimed value?
d) Please describe the condition assessment analysis that was undertaken to determine the high risk condition of the identified conductors.
e) Is the condition of the sleeves and dead ends in the high risk sections of more concern than the condition of the conductor between the sleeves and dead ends?

B-Staff-116
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 2.</u>

At the above noted reference, Hydro One stated the following:

> Hydro One uses an ESL of 90 years for overhead transmission conductors, although the life span of each conductor can vary between 50 and 120 years, as numerous uncontrollable variables affect conductor deterioration, including manufacturing material quality, location, orientation, local atmospheric pollution levels, weather cycles and stringing tension. Currently, about 5% of the overhead conductor fleet has reached or exceeded their ESL of 90 years.

a) Please compare the percentage of assets presently beyond ESL in each Hydro One asset category.
b) Does the conductor fleet represent the asset category with lowest percentage of assets operating beyond ESL among these categories?
c) Please confirm that outages directly caused by spontaneous conductor failure represent a small proportion of all Hydro One outages.
d) Please confirm that this program is proposing significant investments during this test period to replace substantial volumes of an asset class that presently has a better than average demographic profile as compared to other asset classes, and that represents a smaller system reliability performance risk than do other asset classes.

B-Staff-117
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 4, Figure 2.</u>

a) Please confirm that Figure 2 shows a failure at a compression sleeve.

b) What was the cause of failure in this case?

c) Would the failure have been avoided if the sleeve had been replaced prior to the failure event?

d) What was the condition of the remainder of the conductor system in the affected span?

B-Staff-118

Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 6, Figure 4.

a) What was the direct cause of the conductor failure shown in Figure 4?

b) Did the conductor break at or near a splice point, or between splices?

c) What is the percentage of Hydro One conductor failures directly attributable to conductor breakage between splices for events that do not exceed the initial design parameters of the conductor?

B-Staff-119

Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 6, Figure 5.

a) Please confirm that the example in Figure 5 shows a failed splice rather than a failed conductor.

b) Please compare the relative cost of replacing a sleeve or dead end fitting versus the cost of replacing 3 to 4 km of conductor (i.e. the distance between splices for typical reel lengths).

c) Does Hydro One preferentially replace entire reels of conductor in situations where the conductor system deterioration is focused at sleeves and/or dead end fittings?

B-Staff-120

Ref: (1) Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 9, Tables 2 & 3,
(2) SR-20, pp. 5-6, Table 2
(3) TSP Section 3.1, p. 14.

At the third reference above, Hydro One stated the following:

Transmission line sections are comprehensively refurbished when major line components are verified through condition assessment to be deteriorated. Hydro One will invest $425 million to address end of life aluminum core steel-reinforced (“ACSR”) and copper conductor and structures (see ISD SR-19), and $493 million for near end of life ACSR conductor (ISD SR-20). These investments aim to replace a total of 2,127 km, including about 224 km of copper conductor, which is the oldest conductor type in the system and is obsolete since Hydro One can no longer mend certain broken copper conductors. Hydro One will also refurbish steel structures with associated conductors and other lines assets where it has determined that it is economical to replace the entire structure as part of the line refurbishment.

a) The tables above indicate that approximately 247 km of EOL ACSR Conductors are being replaced as part of SR-19 and approximately 775 km of EOL ACSR conductors are being replaced a part of SR-20. Earlier in the Filing Hydro One stated that a total of approximately 1,900 km will be replaced as part of SR-19 and SR-20 (2,127 km - 224 km = 1,903 km). Please reconcile these differences.
b) Table 3 indicates that approximately 580 km of copper conductors will be replaced, but earlier in the Filing Hydro One states that only 224 km of copper conductor would be replaced. Please reconcile these numbers.
c) Do projects listed in the above tables all involve replacement of 100% of the conductor on all phases in the affected segments?
d) Will all or most of the structures and hardware also be replaced at the same time?
e) In respect of the 1,900 km of conductor slated for replacement that is not copper:
    i. How many "events" or "customer delivery point interruptions" have been directly caused by failures of these conductors?
    ii. What are the key drivers for replacement of the 1,900 km of ACSR conductor? If condition, please identify the condition deficiencies by percentage of line affected (e.g. corrosion, broken aluminum strands, birdcaging, etc.)
    iii. Are any conductors proposed for replacement primarily due to the condition of splices? If yes, please list and quantify total km affected.
f) How will Hydro One account for copper salvage value associated with the 224 km of copper conductor replacements?

B-Staff-121
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 13, Table 7.

a) Please explain the volatile inter-annual net investment costs shown in Table 7 for planned replacements during the test period, with specific focus on the inter-annual variations in the "Tx Line Refurb: Placeholder, Expected EoL Line Discoveries" line item.

B-Staff-122
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 14.

At the above noted reference, Hydro One stated the following:

> As shown in Figure 1, demographics for Hydro One overhead conductors demographics that have reached and exceeded EOL is increasing, thereby necessitating the replacement of those deteriorated EOL conductors. Line refurbishment investments are increasing over the test year period as compared to historical years which reflects the increase in circuit kilometres that are being replaced.

a) The above statement appears to conflate demographics and EOL as replacement/refurbishment drivers. Please confirm that Hydro One establishes EOL by asset condition and not by demographic profile.
b) Please confirm that the EPRI study filed as TSP Section 1.4 Attachment #4 (Derivation of Overhead Conductor Hazard Function) demonstrated an inconclusive relationship between ACSR conductor age, corrosion zone and conductor condition.

B-Staff-123
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-19, p. 14.

At the above noted reference, Hydro One stated the following:

> The following factors also influence the costs of Line Refurbishment Projects:
>
> - The circuit voltage level, site accessibility, structure type (wood pole vs. steel structure);
> - The length of conductor being replaced;
> - Whether replacement of deteriorated shieldwire, insulators, or additional hardware is required; and

- Any structure or foundation work required.

a) Do Hydro One conductor replacement projects typically (or always) include replacement of suspension hardware, armour rods and vibration dampers/spacer dampers? Please list any other equipment or hardware typically replaced at the same time as conductor.

B-Staff-124

Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-20, p. 4.

> Table 1 contains information from the projection model. It shows that the amount of circuit kilometers of conductors expected to be in high risk condition over the next twenty years is about 42% of the fleet. As such, it is prudent for Hydro One to proactively engage in conductor replacement, so to ensure that the collective High Risk conductor assets are managed in a timely manner that maintains system reliability and limits the safety risks. Failure to address the issue proactively would result in unmanageable risk and Hydro One will be in a position where it would not be feasible, even impossible, to manage the set of cumulative assets deteriorated to EOL condition.

a) Are the values in Table 1 net of the replacements proposed in the line refurbishment projects identified in SR-19?
b) Is "high risk condition" as used in this paragraph synonymous with "beyond ESL"? If not, what is the basis for predicting that 42% of the fleet will be in High Risk Condition?
c) Are all conductors in Hydro One's fleet that are presently beyond ESL considered to be in High Risk Condition?
d) What is the total percentage of Hydro One's conductor fleet that would be beyond ESL in 20 years if no conductor replacements were implemented under a conductor-condition driven program?
e) What proportion of Hydro One's conductor fleet is presently replaced each year under programs and projects other than this conductor-condition driven program? Does that value consider the average amount of transmission line replaced each year as part of storm restoration activities, including force majeure events?

B-Staff-125
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-20, p. 6.

At the above noted reference, Hydro One stated the following:

> Operating a circuit with near EOL conductors subjects that circuit to an increased likelihood of failure, which threatens reliable operation of the system. Line refurbishment will alleviate this threat.

a) What is the average annual likelihood of conductor failure per Hydro One circuit km? The answer should only refer to outages directly caused by conductor failure, and should not include outages caused by structure, hardware, insulator or splice/deadend failures, loading conditions that exceed the design specifications, or by contact between conductors and trees, other conductors/shieldwires, vehicles, buildings, the ground or other objects.

B-Staff-126
Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-21, p. 1 and EB-2016-0160, Exh B1/Tab 3/Sch 11/Reference #: S75.

At the first reference above, Hydro One stated the following:

> The Program targets the replacement of approximately 800 wood poles each year, totaling 4000 wood poles over the five year planning period. Hydro One has evaluated various alternatives for the Program, as described below and concluded that the most cost effective and efficient undertaking is to proactively replace end of service life wood poles. The projected costs of the Program are estimated to be $156.1 million over the 2020-2022 test period.

At the second reference above, Hydro One stated the following:

> **Investment Name: 2017-2018 TX Wood Pole Replacements**
> The wood pole structures scheduled for replacement in the test years will be replaced with new wood pole or composite structures. The proposed plan will be to replace approximately 850 wood poles in each of the test years 2017 and 2018. This represents an average annual replacement rate 2%. This rate of replacement has been able to keep pace with end of life wood poles identified through inspections as well as address other known wood pole deficiencies, such as the Gulfport structures, on the transmission system.

a) In its previous TSP filing (EB-2016-0160), Hydro One proposed to replace approximately 850 wood poles in 2017 and 2018 to keep pace with end of life wood poles as part of the S75 project "2017-2018 Tx Wood Pole Replacements".

i. How many wood poles were replaced in each of 2017 and 2018?
ii. What percentage of the wood poles replaced in years 2017 and 2018 were end of life wood poles planned for replacement?
iii. How many wood poles were replaced in 2019 (to date), and how many are planned for replacement for the remainder of 2019?
iv. How many wood poles planned for replacement over the last 3 years were not replaced, and have been subsequently deferred into this test period?
v. What is the expected deterioration rate of wood poles that were not at end of life at the time of the last application? In other words, what percentage of the fleet will incrementally deteriorate into end of life condition in each year of the test period?

b) Please describe and provide rationales for changes made to the pole replacement program since Hydro One's previous filing (cost-wise and number of poles).

B-Staff-127
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-21, p. 5, Figure 4.</u>

a) Please provide a count of the wood pole failures identified in Figure 4 during 2016 and 2017 that were caused by:
   - force majeure events
   - extreme wind, snow or ice loads in excess of original design parameters
   - contacts with vehicles
   - treefalls

B-Staff-128
<u>Ref: Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-24, p. 1 and TSP Section 3.1, p.14.</u>

At the first reference above, Hydro One stated the following:

> If EOL shieldwire is not replaced, it is likely to break and make contact with the conductor, resulting in a circuit outage and potential customer interruption.

At the second reference above, Hydro One stated the following:

> Hydro One will invest $64 million over the five-year plan to assess and replace shieldwire that does not meet current design requirements (ISD SR-24). This will address shieldwire that is at risk of mechanical failure (including falling to the ground).

a) What is the average annual probability of shieldwire failure in the segments identified in this program over the test period, expressed as expected annual failures per circuit km?
b) What is the basis of not meeting current design requirements?
c) Is the shieldwire replacement primarily condition driven, or has Hydro One done engineering to demonstrate that even good condition shieldwires are at risk of mechanical failure due to excessive span length, or interference with phase conductors due to heavy loading sag and/or galloping risk? Please provide details.

B-Staff-129

<u>Ref: (1) Exh B/Tab1/Sch 1/TSP Section 3.3, Attachment ISD: SR-25, p. 1,</u>
<u>(2) TSP Section 3.1, pp.16-17,</u>
<u>(3) TSP Section 3.3, p. 7,</u>
<u>(4) TSP Section 1.4, p. 17.</u>

At the first reference above, Hydro One stated the following:

> **A. OVERVIEW**
> Transmission Lines Insulator Replacement Program (the "Program") involves primarily the replacement of defective porcelain insulators manufactured by Canadian Ohio Brass (COB) and Canadian Porcelain (CP) between 1965 and 1982. These defective insulators are used province-wide in Hydro One's transmission system.

At the second reference above, Hydro One stated the following:

> As noted above, porcelain insulators manufactured by COB and CP between 1965 and 1982 are known to be defective and susceptible to mechanical and electrical failure. There are approximately 34,000 circuit structures with defective porcelain insulators, including about 15,000 that have been identified as being on structures in critical locations (i.e., near roads, water railways, urban areas, golf courses, educational and health care facilities). Failed insulators typically result in a sustained forced outage because of the resulting permanent electrical fault. Repair time can be prolonged, averaging 36 hours per outage, depending on the location and severity of the failure. To date, Hydro One has replaced approximately 8,900 publically accessible COB and/or CP insulators.

At the third reference above, Hydro One stated the following:

> In 2016, investment in transmission stations saw an overall increase of $147 million to address deteriorated, poor condition assets in addition to projects from previous years that were under construction and had significant portions carry over into 2016 including work at Allanburg TS, Gerrard TS, and Beck 2 TS. Transmission line refurbishments contributed $62 million to the overage due to increased wood pole replacement needs based on poor condition and increased expenditures to replace defective CP/COB insulators to mitigate public safety risk.

At the fourth reference above, Hydro One stated the following:

> After testing 591 samples, EPRI found overwhelming evidence to support the recommendation that Hydro One should remove the fleet of COB and CP porcelain insulators from service as soon as is practically possible to mitigate the risk of safety and reliability. Based on the results of Phase 2 COB/CP testing, insulators posing a higher public safety (i.e. insulators in critical locations) will be replaced by 2022 at a rate of approximately 3,700 circuit structures per year.

a) In which year were serious problems with COB porcelain insulators first identified?
b) How many of the problematic COB insulators have been replaced each year since the problems were first identified (expressed either as total number of bells replaced, or total percentage of the initially identified problematic COB bells replaced).
c) What percentage of the originally identified problematic COB porcelain bells are still in service in the Hydro One system at present?
d) Hydro One received approval to replace a large number of COB porcelain insulators in its prior cost of service filing.
    i. What percentage of the 2016 COB insulator fleet was replaced since the last filing?
    ii. What percentage of the COB insulator replacements planned for the past test period was deferred? Quantify the associated deferred capital cost and provide the reasons for the deferral.
e) What proportion of the 2016 COB insulator fleet will have been replaced by 2024 if the replacement program proposed in this TSP is followed?
f) What will be the residual percentage (or count) of COB insulator fleet expected to be left to replace following the present planning period?
g) In the second reference, please confirm that the last sentence in the above reference refers to 8,900 COB insulator bells rather than 8,900 insulator strings.
    i. If confirmed, how many structures does this represent?

h) How many faulty COB insulator bells are installed on the 34,000 circuit structures with defective insulators and the 15,000 in critical locations referred to in the above paragraph?
i) Please provide all-in cost of replacing COB insulators each year from 2015 to 2019.
j) How many insulator bells were replaced in each year from 2015 to 2019?
k) What was the average all-in replacement cost per bell in each year (categorized by bell strength rating, as appropriate)?
l) Has Hydro One modified its specification and procurement processes to ensure that similar porcelain insulator issues are avoided in future widespread applications?
    i. If yes, please provide details.
    ii. If no, please explain why not.

B-Staff-130
Ref: Exh B/Tab2/Sch 1/p. 3, Table 1.

a) Does Table 1 account only for the cost of projects and programs identified in the prior filing?
b) Please identify all projects in the prior filing that were not completed as planned.
c) Please identify the percentage of spending by program in the prior filing not completed as planned, or in excess of plan.
d) What was the average variance in percentage between estimated cost and final cost for the projects identified in the prior filing, and what was the standard deviation around that average variance?
e) What is the total value of projects and programs identified in the prior filing that have been deferred into the present planning period?

B-Staff-131
Ref: Exh B/Tab 2/Sch 1, page 46 of 54

At the above reference, it is stated that:

> As changes to investments or other circumstances occur during the year, Hydro One reprioritizes during execution as new information may change one or more projects' expected value, timing, cost, customer needs, etc. In 2017, Hydro One formalized a Redirection Committee to appropriately redirect funds or authorize additional spending

as necessary. Such redirection or allocation allows prudent and timely adjustments to be made to the work originally identified in the investment plan.

The Redirection Committee meets once a month. Following the review and recommendation of plan adjustments, investment level decisions are documented and communicated to appropriate stakeholders, including the recommended change and rationale. Updates regarding significant Redirection Committee decisions, as well as recommendations related to reprioritization options that require an approval authority that exceeds that of members of the committee are communicated to the ELT.

a) Please quantify the investment adjustment decisions, at the project/program level, made by the Redirection Committee on a monthly basis for 2017 and 2018. Please also:
   i. Provide examples of "significant Redirection Committee decisions".
   ii. Explain the rationales of adjusting investment plans.
   iii. Explain how the reprioritization options were selected.

B-Staff-132

Ref: (1) Exh C/Tab 1/Sch 1/p. 3, Table 2,
(2) Exh A/Tab 3/Sch 1/p. 26 Table 5,
(3) Exh A/Tab 3/Sch 1/p. 47 Table 14,
(4) Exh B/Tab 1/Sch 1/TSP Section 1.3 Attachment 1, pp. 44-47.

a) Table 2 above indicates that Hydro One's Transmission Rate Base is growing significantly faster than inflation, while the forecast load peak is decreasing (per Table 5). Please explain the reason for this inverse relationship.
b) Was the net impact of 8.7% on 2020 average transmission rates shown in Table 14 communicated to customers during the customer outreach sessions? If yes, please provide documentation.
c) Was an 8.7% year-one (i.e. 2020) rate increase assumed when calculating any of the average annual transmission rate increases shown in Illustrative Scenarios A, B, C or D (Reference 4)?
   i. If yes, please identify which scenario.
   ii. If no, please explain why not.
d) Were the average annual rate increases shown in the Illustrative Scenarios calculated using the same methodology shown in Table 14, i.e. considering the net impact of both revenue requirement growth and declining load forecast?

i. If no, please show what the average annual transmission rate increases would have been for all Illustrative Scenarios if the rate calculations had followed the same methodology.

B-Staff-133
Ref: Exh C/Tab 2/Sch 1/Attachment 1, p. 14.

At the above noted reference, Hydro One stated the following:

> In its subsequent "DRO Update" dated November 16, 2017 which was submitted in response to the DRO Order, Hydro One addressed the points raised by the OEB in the DRO Order with an explanation about how it allocated capital reductions in the draft rate order for 2017 (where possible) and 2018 by providing the following additional information:
>
> - In "Overhead Lines Refurbishment Projects, Component Replacement", the company reduced the tower coating and shieldwire replacement programs and its deferred line refurbishment projects.
> - In "Integrated Stations", at the time the Decision was issued, 98% and 75% of the portfolios for 2017 and 2018, respectively, were already in execution. Cancelling those projects would result in significant inefficiencies and stranded costs. Deferring the remaining 25% of the 2018 "Integrated Stations" projects would negatively impact reliability. These projects include investments at Kingsville, Leaside, Cherrywood, Sheppard, Detweiler, Minden, Gage and Stanley transformer stations.
> - Reductions in the Development capital forecast were largely driven by changes in customer demand and project forecasts. The Development projects most impacted are investments at Clarington TS (-$38 million), Lisgar TS (-$7 million), Runnymede TS (-$13 million) and Hanmer TS (-$8 million).

a) Were the deferrals mentioned in the first bullet based upon Hydro One's assessment that they represented lower reliability performance and safety risk than projects that were not deferred?
b) Please explain in detail how changes in customer demand and project forecasts influenced the reductions listed in the third bullet.

B-Staff-134
Ref: Exh C/Tab 2/Sch 1/Attachment 1, p. 15, Figure 1.

a) Please provide the information in Figure 1 categorized using the standard OEB classifications (System Access, System Renewal, System Service and General Plant).

B-Staff-135
Ref: EB-2018-0098, Exh B/Tab 5/Sch 1/p. 1.

At the above noted reference, Hydro One stated the following:

> **Alternative 2 –** Perform one or a combination of the following; Increase operating temperature, replace existing wood poles with higher structures, increase conductor tension on existing wood poles.
>
> The three design alternatives identified in Alternative 2 are cost effective only if the conductor is in fair condition, and has considerable service life remaining. The existing conductor is of 1950 vintage and it is predicted to have approximately 10-15 years of service left before reconductoring is required. This reconductoring due to age/end of life will be required in the near future regardless of any interim design solutions to help increase the thermal ratings. Consequently, to achieve cost synergies and to avoid double customer and community construction impacts over a short time period, Alternative 2 was not explored further.

a) What conductor ESL was assumed in this remaining life assessment?
b) What would the remaining service life have been if a 90 year ESL had been used?
c) Would a remaining conductor service life of 30 to 35 years have been considered adequate to justify considering the Alternative 2 modifications? Would it have been physically possible to upgrade the line to meet the IESO's ampacity requirements for H9K using a combination of the Alternative 2 modifications?
    i. If yes, what is the estimated cost of implementing the required modifications?
d) What was the assessed overall condition of the existing conductor, poles, hardware, insulators, shield wires and other components of H9K at the time the Leave to Construct application was initially filed with the OEB?

B-Staff-136
Ref: EB-2018-0098, Exh B/Tab 7/Sch 1/p. 1, Table 1.

a) The original cost estimate for the "10 MVAr reactive support" project component was $4 million. What is the current estimate for this component?
b) The original cost estimate for the "10 MVAr capacitive support" project component was $2 million. What is the current estimate for that component?
c) What was the initial estimate quality associated with each of these components, using the AACE estimate classification system and also expressed in terms of +/- percentage range?
d) What is the present estimate quality for each of these components using the same system?
e) Does the updated estimate include other incremental substation components that cannot be classified as either reactive support or capacitive support and cannot be attributed prorata to either of those primary project components? Please provide details of all such unattributed project components and explain why they are now required to satisfy the IESO's functional specifications for the KAR project.
f) Did Hydro One inform the OEB of the initial estimate quality and range when the LTC application was submitted?
g) Did Hydro One inform the OEB of the present estimate quality and range when submitting the revised cost estimates in March 2019?
h) Please provide a detailed description of all site-specific and non-site-specific factors that were considered when Hydro One developed the initial reactive and capacitive support project component estimates.
i) What new information became available following the initial LTC application regarding each of these project components that informed the cost variances identified in the revised estimates filed with the OEB in March 2019?
j) What additional design and procurement work has been done between the time the initial LTC application was submitted and the issuance of the revised cost estimate?
k) Has project scope changed since the initial cost estimate?
    i. If yes, what triggered the scope change?

ii. If yes, were all changes authorized through Hydro One's project management process?

l) What are the detailed drivers that caused the variance between the initial and revised cost estimates?

m) Did Hydro One originally estimate the substation component additions as if this was a greenfield project, or was the initial estimate developed with the understanding that this is a brownfield renovation-type project?

n) Would Hydro One consider it to be good utility practice to develop a brownfield construction estimate using greenfield construction site assumptions?

o) Did Hydro One apply the same level of estimate diligence and expertise to estimating costs for the substation components as it applied to estimating the line component costs? If no, please explain why not.

p) What would Hydro One do differently in preparing and submitting a Leave to Construct application for a similar facility today?

B-Staff-137

Ref: EB-2018-0098, Exh B/Tab 7/Sch 1/p. 2.

At the above noted reference, Hydro One stated the following:

> **1.0 RISKS AND CONTINGENCIES**
> As with most projects, there are risks associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks.
> The top 3 project risks are outlined below. These risks are the major contributors to the total contingency suggested for this project.
>
> - **Resource shortage –** there is a risk of resource shortages due to multiple projects that are set to be in execution at the same time in the general area of the KAR Project. This may lead to schedule delays and additional costs.
> - **Outage constraints –** there is a risk that securing an outage will not be supported by customers in the area and this may result in schedule delays and additional costs.
> - **Aggressive timelines** - there is a risk of not meeting the in-service date due to the aggressive timelines set on the Project (14 months following the leave to construct approval).

a) Were any of the top three project risks identified in the LTC application key drivers of the reactive and capacitive project component cost estimate variances? If yes, please explain in detail.
b) Was Hydro One aware when the LTC application was prepared that unknown construction complexities associated with a brownfield construction site were a potential project cost risk, even though not listed as one of the top three project cost risks, or should this risk be categorized as "Any other unforeseen and potentially significant event/occurrence" that was not included as a cost contingency "due to the unlikelihood or uncertainty of occurrence"?

B-Staff-138
Ref: EB-2018-0098, Exh B/Tab 7/Sch 1/p. 3.

At the above noted reference, Hydro One stated the following:

> The comparable lines project, D2L Dymond x Upper Notch Junction was a line refurbishment project from Dymond TS to Upper Notch Jct Structure 261. The D2L Line Refurbishment included wood pole replacement, shieldwire replacement, like for like conductor replacement as well as line hardwares, dampers, u-bolts and insulators. The project went in-service in August of 2017. The main driver of the variance in comparable costs between the two projects is the number of wood pole replacements. H9K will replace 324 wood poles while D2L replaced 60 H-frame wood poles. Additionally, the H9K Project involves extra cost for multiple river crossings, access and terrain challenges such as swampy-like conditions.

a) Please explain why the “comparable projects” section of the LTC considers a project that primarily involved only line components.
b) In retrospect, was the selected comparable project an appropriate basis of comparison for a project for which the estimated cost of the station components exceeds the cost of the line components?

EXHIBIT C – RATE BASE

C-Staff-139
Ref: Exh C/Tab 8/Sch 2/p. 1 & 2

At the above noted reference, Hydro One stated the following:

> Hydro One capitalizes costs that are directly attributable to capital projects and also capitalizes overhead costs supporting capital projects. The overhead capitalization rate is a calculated percentage representing the amount of overhead costs that are required to support capital projects in a given year…
>
> …In 2007, Hydro One Networks began reviewing the overhead capitalization rate on a quarterly basis to determine if the rate needed to be changed to reflect in-year changes in capital spending and associated support costs. At year-end, capitalized overheads are trued-up to reflect actual results. This results in a better alignment of overhead costs with the capital projects that they support. Hydro One proposes that the overhead capitalization methodology, as reviewed in the B&V study in 2018, continues to be a reasonable method of distributing common corporate costs to capital projects. Hydro One's submissions in this Application reflect this overhead capitalization methodology.

At the above noted reference, Hydro One also provided a table (Table 1) that showed the forecast overhead capitalization rate is expected to decrease from 11% in 2019, to 10% in 2020 and 2021, and further to 9% in 2022. However, despite the declining trend in the overhead capitalization rate, the actual amounts capitalized are expected to increase from $114.1 in 2019 to $119.4 in 2020, to $122.6 in 2021, and $123.8 in 2022. As a result, the amounts capitalized have increased by $5.3 million or 4.6% between 2019 and 2020, whereas the overhead capitalization rate has decreased by 9.1% over the same period from a rate of 11% to 10%.

Hydro One also stated that "the capitalization rates are down relative to the previous transmission study mainly due to higher planned capital expenditures and lower OM&A."

a) Please explain why despite the declining trend in the overhead capitalization rate, the actual amounts capitalized are expected to increase.

b) Please update the table provided at the above noted reference with actuals from 2015 to 2018, as well as OEB approved 2017 and 2018, and explain any trends.

c) Please quantify and explain Hydro One's above noted statement that "the capitalization rates are down relative to the previous transmission study mainly due to higher planned capital expenditures and lower OM&A."

d) Please provide an overall explanation as to why there is an increased percentage of costs allocated to rate base in this proceeding versus the previous transmission proceeding.

C-Staff-140
Ref: Exh C/Tab 8/Sch 2,

At the above reference, Hydro One discusses its methodology for capitalizing its overhead costs under US GAAP.

a) Over the term of this transmission rates application, please indicate how much more Hydro One is able to capitalize as a result of being on US GAAP compared to if it were following the OEB's MIFRS capitalization policy. If possible, please provide the analysis by year over the term of this application.
b) If a regulator were to order a utility to capitalize less for regulatory purposes than what is permitted under US GAAP, what implications would such a decision have on the US GAAP based financial statements?
c) In light of the fact that Hydro One reports into the Ontario government under IFRS for purposes of preparing the province's consolidate financial statements, has Hydro One considered moving to IFRS for its own financial statement reporting?
d) One of the main concerns that Hydro One raised in support of its transition to US GAAP was that IFRS did not allow for rate regulated accounting and therefore it would create significant volatility in its financial reporting. Now that IFRS does allow for rate regulated accounting and is in the process of developing a standard on regulated accounting, has Hydro One considered moving to IFRS?

C-Staff-141
Ref: Exh C/Tab 8/Sch 2/p. 3

At the above noted reference, Hydro One stated the following:

> …Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs, is within the observed range and essentially consistent with the median found in Hydro One's industry research of other Canadian and US utilities.

a) Please provide an analysis which shows that Hydro One's overhead capitalization rate, when expressed as a percentage of gross operating costs and also as percentage of capital, is within the observed range and consistent with the median found in Hydro One's industry research.

C-Staff-142

Ref:

(1) Exh C/Tab 8/Sch 2/Attachment 2
(2) Exh C/Tab 8/Sch 2/p. 1 & 2

At the above noted first reference, Hydro One showed an overhead capitalization rate of 24% for 2019 and 2020. However, at the second reference overhead capitalization rates of 11% and 10% are shown respectively for 2019 and 2020.

a) Please explain the different overhead capitalization rates that are shown for 2019 and 2020.

C-Staff-143

Ref:

(1) Exh C/Tab 8/Sch 2/Attachment 1/ *Review of Overhead Capitalization Rates (Transmission) – 2019 Black & Veatch Project No. 188588*
(2) Exh F/Tab 2/Sch 6/Attachment 1/ *Review of Allocation of Common Corporate Costs (Transmission) – 2019 Black & Veatch Project No. 188588*
(3) Exh C-3-1/Attachment 1/ *Review of Shared Assets Allocation (Transmission) - 2019 Black & Veatch Project No. 188588.*

a) Please state how the above noted studies in the current application relate to the studies filed in the previous Transmission application and Distribution application.
b) Please provide a table summarizing and comparing the key recommendations of the current studies with those in the previous studies. Please include an explanation for any changes between the recommendations in the current studies and those in the previous applications. Please describe whether and how any changes were made that would materially impact the 2020 test year revenue requirement.

C-Staff-144

Ref:

(1) Exh C/Tab 8/Sch 2/Attachment 1/ *Review of Overhead Capitalization Rates (Transmission) – 2019 Black & Veatch Project No. 188588, p. 4*
(2) Exh F/Tab 4/Sch 1/Attachment 5 (Excel format)

At the above noted first reference, the following is stated:

> Approximately $89 million of labour costs, representing approximately 33% of the annual total Common Corporate Costs (and approximately 42% of annual labour costs), were

> directly assigned between OMA and capital based on a time study performed for the four-week period ending June 9, 2017 ("2017 Time Study")…

At the above noted second reference, total compensation costs from 2014 to 2022 are quantified.

a) Please state whether or not the labour costs allocation in the first reference was incorporated into the total compensation costs shown in the first reference. If not, please explain.

EXHIBIT D – SERVICE QUALITY AND RELIABILITY PERFORMANCE AND REPORTING

D-Staff-145
Ref: Exh D/ Tab 2/ Sch 1- Section 1.2: Transmission Reliability Measures, Table 1: Transmission Reliability Measures and Exh B/Tab 1/Sch 1/TSP Section 1.5.2, Table 2

a) Please compare the above referenced two tables to each other and discuss how the measures in both tables compare to each other and the extent to which the measures and the corresponding description are the same, similar or different?
    i. If they are the same or similar, please explain any differences in the descriptions between the two tables,
    ii. If they are different, why would the measure of reliability performance outlined in Exhibit D not be on the scorecard in the TSP?

D-Staff-146
Ref: Exh D/ Tab 2/ pp. 3-4.

At the above reference, it is stated that:

> Hydro One's comparative reliability performance at the system level is illustrated in the following Figures:
> - Figure 1a - frequency of momentary interruptions;
> - Figure 1b - frequency of sustained interruptions;
> - Figure 2 - overall frequency of interruptions;
> - Figure 3 - average duration of sustained interruptions; and
> - Figure 4 - delivery point unreliability index.

a) Please state whether or not these figures correspond with the measures proposed in Exhibit D/ Tab 2/ Sch 1- Section 1.2: Transmission Reliability Measures, Table 1: Transmission Reliability Measures or Exhibit B-1-1/ TSP Sec 1.5.2- Performance Measurement Methods and Measures, Table 2- Operational Effectiveness Measures.
    i. If they do correspond, please explain any differences in their descriptions.

D-Staff-147

Ref: Exhibit D/ Tab 2/ Sch 1- Section 1.3: External Comparison of Reliability, Figure 5: Unavailability of Transmission Lines

OEB staff notes that in Figure 5, the CEA 5 Year Moving Average indicates a downward trend (improving) starting in 2012. However Hydro One's Unavailability of Transmission Lines has been trending upwards (worsening) starting 2014.

a) Please explain the upward trend.
b) Please discuss Hydro One's plan to reduce Unavailability of Transmission Lines to the CEA level or below.
c) Please explain the 190% increase from 2017 to 2018.

D-Staff-148

Ref: Exhibit D/ Tab 2/ Sch 1- Section 1.3: External Comparison of Reliability, Figure 6: Unavailability of Major Transmission Station Equipment

In Figure 6, the CEA 5 Year Moving Average indicates a downward trend (improving) starting in 2012. However Hydro One's Unavailability of Major Transmission Station Equipment has been trending upwards (worsening) starting 2013, and is currently 60+% above CEA 5 Year Moving Average from 2015 – 2017.

a) Please explain the upward trend.
b) Please discuss Hydro One's plan to reduce Unavailability of Major Transmission Station Equipment to CEA Composite level or below.
c) Please explain the 41% increase from 2017 to 2018.

EXHIBIT E – OPERATING REVENUE

E-Staff-149

Ref: Exhibit E/ Tab 1/ Sch 1- Section 1: Summary of Revenue Requirement, Table 1: Revenue Requirement ($ Millions).

a) Please provide a version of this table with the missing information for 2019: OM&A, Depreciation and Amortization, Income taxes, Return on Capital.

b) Please include with the revised version of this table the reference exhibits for the components listed in Note 3: External Revenue and other: i.e. External Revenue, MSP Revenue, Export Tx Service Revenue and Low Voltage Switch Gear Credit.

E-Staff-150

Ref: Exhibit E/ Tab 2/ Sch 1/ Section 3- Description/ Table 1: External Revenue ($ Million) and EB-2016-0160 Exh E1/Tab 2/Sch 1/Section 3 – Description/ Table 1: External Revenues.

a) Please reconcile the two 2015 Historic Secondary Land use numbers and Other External Revenues and identify the correct amount. Please provide an explanation for the change.

b) OEB staff notes that historically, external revenue has been under forecasted (i.e. 2016- 51% variance; 2017- 26% variance, 2018- 38% forecasted variance). Please explain the large variances between the forecasted and historical external revenues and discuss whether or not Hydro One is looking into a more accurate forecast methodology for external revenues.

E-Staff-151

Ref: EB-2017-0049/ Decision and Order- March 7, 2019/ p. 129

The OEB findings at the above reference “require Hydro One to do further investigation on the use of weather data from multiple locations in the province”.

Please provide an update as to the status of this investigation.

E-Staff-152
Ref: Exh E/Tab 3/ Sch 1/ Appendix B and EB-2016-0160/Exh E1/Tab 3/Sch 1

a) Please identify and explain any updated variables in the annual econometric models at the above references.
b) Please discuss the references to the use of National Energy Board (NEB) forecasts in the current application as these do not appear to have been used in the previous application. Please confirm that this is a change from the previous application and discuss why it was made.
c) Please discuss how the model used in the current application compares to that used in the previous application and to what extent it provides an improved forecast.

E-Staff-153
Ref: Exhibit E/ Tab 3/ Sch 1/ Appendix F and EB-2016-0160/Exh E1/Tab 3/Sch 1.

Please state whether or not the revised model been retroactively applied and a study completed to determine the accuracy of the proposed models and previous models when compared to the historical actuals?

EXHIBIT F – OPERATING COSTS

F-Staff-154
Ref: (1) Exh F/Tab 1/Sch 3/p. 41,
(2) Exh F/Tab 1/Sch 3/p. 40,
(3) EB-2016-0032, Notice of Proposal to Amend a Code, Dec 20, 2017, p. 13

At the first reference above, it is stated that:

Hydro One's overall planned expenditures for Cyber Security Management in the 2020 Test Year are $15.6 million, which is lower compared to the 2015-2018 historical period. This funding is required for the continued maintenance of cyber security assets, conducting annual surveys, and managing, operating and monitoring cyber security systems described above. Increased spending in 2015 and 2016 was a result of efforts to achieve compliance with NERC CIP V5.

At the second reference above, it is stated that:

Compliance with NERC CIP Version 5 ("V5"), which applied to Hydro One's High and Medium voltage transmission systems, increased the cyber security sustainment program by introducing new processes and procedures, many of which must be tested at least every 15 months. Compliance with NERC CIP Version 6 (“V6”) extends requirements to Hydro One’s Low impact classified sites requiring both physical and electronic access controls. NERC CIP V6 brought into scope approximately 60 additional facilities which were not part of the NERC CIP V5 compliance program. The proposed next generation of NERC CIP Version 7 (“V7”) Standards is in the final drafting stages and includes inter-control center communication and virtualization. These standards are expected to be approved with compliance due dates in the 2019-2021 timeframe.

At the third reference above, it is stated that:

…The OEB believes that transmitters and distributors should have already incorporated cyber security into their business and asset planning, consistent with their risk portfolio…

The first reference suggests that costs will be lower in the 2020 Test Year than the 2015-2018 historical period because of increased spending in 2015 and 2016 as a result of efforts to achieve compliance with NREC CIP V5.

The second reference would suggest that in the Test Year period costs to achieve compliance with V5 will continue and there will also be additional costs related to V6 and V7.

a) Given the above, please explain why Hydro One believes it is reasonable to assume that expenditures on cyber security costs in the Test Year will be lower than they were in the 2015-2016 period.

b) Please explain why Hydro One is seeking incremental costs for cyber security in OM&A when as noted above, transmitters should have already incorporated cyber security into their business and asset planning.

F-Staff-155

Ref: Exh F/Tab1/Sch 3, p. 47 and EB-2017-0049/Exh Q/Tab 1/Sch 1, pp. 12-13

At the first reference above, Hydro One’s approach to vegetation management in the current application is discussed.

At the second reference above, which is an update filed in December 2017 from Hydro One’s recent distribution rates application, Hydro One’s new vegetation management strategy is discussed and it is stated that:

Since the Application was filed, Hydro One has continued to further explore opportunities for continuous improvement in vegetation management and innovative approaches working with Clear Path Utility Solutions LLC. ("Clear Path"), an expert in utility vegetation management. A quantitative workload study was conducted by Clear Path which measured Hydro One's maintenance backlog and future workloads and recommended a vegetation management strategy designed to improve the condition and reliability of Hydro One's right-of-ways….

Based on Clear Path's recommendations, Hydro One has developed a new vegetation management strategy that maintains corridors on a three-year cycle, focusing on defects rather than completely clearing vegetation in a corridor. This defect-based approach will address vegetation that poses a public safety or reliability threat because it is either (a) growing into or will grow into energized equipment within the three-year maintenance cycle, and/or (b) dead/dying vegetation that will likely cause system interruption and/or equipment damage within the maintenance cycle.

a) Please discuss how Clear Path's study has impacted the current application.

F-Staff-156
Ref: Exh F/Tab 1/Sch 3, p.10 Table 3

The above referenced table provides Hydro One's environmental management OM&A which is shown as increasing from $16.7 million in 2017 to $22.1 million in the 2020 Test Year, representing an increase of $5.4 million or 33%.

OEB staff notes that this overall increase is made up of significant increases in the categories of "PCB Retirement and Waste Management" and "Environmental Compliance and Emergency Response Plan Updates", offset by significant decreases in the other two categories of "Transformer Oil Leak Reduction" and "Preventative and Corrective Maintenance."

a) Please discuss the extent, if any, to which the cuts in spending in the latter two categories are related to the increases in the former two categories.
b) Please discuss whether or not the reduced spending levels in the two categories with reduced spending are considered to be sustainable, or one-time in nature.

F-Staff-157
Ref: Exh F/Tab 1/Sch 3, p.11

At the above reference, it is stated that:

However, to manage its OM&A spending, in 2019, Hydro One deferred a planned increase to its PCB program, which resulted in a reduced buffer period to comply with the Environment

Canada deadline. Hydro One anticipates completing the required PCB remediation by 2024, which is one year later than previously planned, but which leaves only a one-year buffer period for completion of the work within the required timeframe.

a) Please state whether or not the deferred planned increase to Hydro One's PCB program to manage OM&A spending in 2019 was entirely incorporated into the 2020 spending or was spread over the anticipated spending on this program in the 2020 to 2024 period on an equal basis.

b) Please describe the impact on the 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital, if the one-year buffer period is eliminated and Hydro One completes this work in 2025, instead of completing by 2024. Please explain the associated risks of deferring this work further to 2025.

F-Staff-158
<u>Ref: Exh F/Tab 1/Sch 3, p.12 and p.10 Table 3</u>

At the first reference above, it is stated that:

As part of the Transformer Oil Leak Reduction program, Hydro One plans to re-gasket 5 or 6 transformers per year, which is in line with the historical average.

At the second reference above, the proposed spending for 2020 in this category is $2.5 million, with spending varying in the 2015 to 2018 period from a low of $0.9 million in 2015 to a high of $4.1 million in 2017.

b) Please state what period the historical average represents.
c) Please explain the reasons for the variability of spending in this category in the 2015 to 2018 period.

F-Staff-159
<u>Ref: Exh F/Tab 1/Sch 3, pp.14-15 and p.10 Table 3</u>

At the first reference above, the Environmental Management OM&A category of "Environmental Compliance and Emergency Response Plan Updates" is discussed and it is stated that funding for Emergency Response Plans for the 2020 Test Year is in line with historical expenditures. With respect to Environmental Compliance, it is stated that:

The program was forecasted based on Ontario's Cap and Trade Regulations and was repealed on October 31, 2018. The regulations included detailed rules and obligations for businesses, such as Hydro One. In December 2018, the Ontario Government announced its new environment plan that is aimed at, among other things, addressing climate change by lowering greenhouse emissions. Details of the plan are not yet available. Furthermore, on October 23, 2018, the Government of Canada confirmed that Ontario would be covered by the federal Greenhouse Gas Pollution Pricing Act which imposes a price on greenhouse gas emissions in the province beginning in 2019.

At the above second reference above, spending for the 2020 Test Year is shown as $3.3 million, with spending in the 2015 to 2018 period ranging from $0.9 million to $1.8 million.

a) Please confirm that the significant increase in spending in this category in the 2020 Test Year arises from an increase in the Environmental Compliance component. If this is not the case, please explain the statement referenced above that funding for Emergency Response Plans for the 2020 Test Year is in line with historical expenditures.
b) Please state what component for the $3.3 million spending in this category is for Environmental Compliance and how Hydro One determined it was reasonable given the above reference to details of the Ontario Government's new environmental plan not being available when the forecast was being prepared.

F-Staff-160
Ref: Exh F and EB-2017-0049 *Decision and Order,* Appendix 2

At the second reference above, the OEB directs Hydro One to do as follows:

Demonstrate, in future applications, that OM&A options are being explicitly considered in investment decisions to either replace or defer capital investments, as applicable.

a) Please discuss how Hydro One has reflected this direction in the application.

F-Staff-161
Ref: Exh F and EB-2017-0049 *Decision and Order,* Appendix 2

At the second reference above, the OEB directs Hydro One to do as follows:
For any future Hydro One rebasing application, develop a consistent template for presenting compensation costs based on the direction provided by the OEB in prior proceedings.

a) Please discuss how Hydro One has reflected this direction in the application.

F-Staff-162
Ref: Exh F/Tab 1/Sch 1 p. 3

At the above reference, Hydro One states that:

Hydro One's 2019 OM&A expenses are expected to be $38 million or 9.6 percent lower than the 2018 plan funding envelope. This OM&A reduction will be achieved largely through sustained productivity gains, a one-time extension of Hydro One's planned asset maintenance cycles, and corporate cost reductions, which are described further within Section 6 of this Exhibit. Hydro One plans to increase its 2020 OM&A expenditures by 5 percent from 2019 levels while still remaining 4.7 percent below the 2018 plan funding envelope. The investment plan was designed to utilize the approved funding to improve reliability and maintain asset condition over the planning period. In this manner, the investment plan appropriately balances the need to minimize customer rate impacts with the requirements of the system for supporting the delivery of safe and reliable transmission service.

a) Please discuss whether or not Hydro One's ability to remain 4.7 percent below the 2018 plan funding envelope approved in the previous transmission application would reasonably raise concerns that it may be over-forecasting OM&A requirements in the current application.
b) Given that Hydro One's OM&A expenditures were running below the envelope approved in the previous application, please explain why it was considered necessary to undertake the above referenced one-time extension of planned asset maintenance cycles, along with the other cost containment measures also described.

F-Staff-163

Ref: Exh F and EB-2016-0160 *Decision and Order* Revised: November 1, 2017, pp. 62-63

At the second reference above, the OEB expressed its concern about Hydro One's historic pattern of OM&A under-expenditure since 2012 and provided the following direction:

In future applications, the OEB directs Hydro One to provide a high level description of the main contributors to any material variance between approved and actual total OM&A expenditures in previous applications and the impact of those variances on its longer-term ability to operate and maintain its assets. This information would enable the OEB to determine if there are fundamental issues affecting Hydro One's ability to complete the planned work program and the potential impact of these issues on future proposed work programs.

a) Please discuss how Hydro One has complied with this direction in the current application.

F-Staff-164
Ref: Exh F/Tab 1/Sch 5 p. 3

At the above reference, Hydro One states, in providing variance explanations for Operations OM&A, that:

The 2020 test year proposed spending represents an increase of $2.8 million relative to the 2019 bridge year forecast expenditures. The increase is necessary to reinstate the Operations Support work programs that were part of the unsustainable reductions in in 2018 and 2019 as noted below. Even with this increase, the 2020 proposed level still remains below the previous Board-approved amounts.

a) Please explain why Hydro One considered it necessary to make an unsustainable reduction in Operations Support work programs in 2019 to align with the OM&A envelope in the inflation application. Please discuss this in the context of the statement that the 2020 proposed level still remains below the previous Board-approved amounts.

F-Staff-165
Ref: Exh F/Tab 2/Sch 4 p. 11

At the above reference, Hydro One discusses anticipated reductions in its IT Management and Project Control OM&A Allocated to Transmission and states as follows when explaining the significant reductions in these costs anticipated for 2019 and 2020:

Historical actuals for IT Management & Project Control are trending down. The proposed IT Management & Project Control OM&A expenditure for the 2020 Test year is 22.1%, 41.2% and 4.8% lower than the 2018 forecast expenditure, 2018 Plan and 2019 Forecast amounts respectively. Hydro One attributes this decreasing trend to an updated actuarial pension valuation, which reduced operating expenses across the company, lower headcount and increased labour recovery related to IT capital projects portfolio expenses.

a) Please clarify whether or not the reference to lower headcount relates to general reductions, or reductions specific to the IT area.
b) Please explain why there was increased labour recovery related to IT capital projects portfolio expenses.

F-Staff-166
Ref: Exh F/Tab 2/Sch 4 p. 14

At the above reference, Hydro One explains changes in the ratio of IT spend as a percentage of operating expense and states that “2017, 2018, 2019 and 2020 figures reflect lower costs of power related to Fair Hydro Plan.”

a) Please state why Hydro One cited this specific factor in explaining these changes.

F-Staff-167
Ref: Exh F/Tab 3/Sch 1 p. 5

At the above reference, it is stated that:

Inergi’s services are also measured through client satisfaction surveys conducted by Inergi of Hydro One’s relevant business managers and internal users. Inergi must address dissatisfaction revealed by the surveys. Together, Hydro One and Inergi are to identify opportunities and strategies for responding to any issues the surveys reveal. The most recent surveys showed scores of 3.32 out of 5 for Base Services and 3.96 out of 5 for Project Services and service desk support.

a) Please comment on the above scores, in particular the 3.32 out of 5 for Base Services and whether these scores reveal any issues with the services provided by Inergi to Hydro One. If the scores reveal any issues, please explain what they are and what is being done about them. If they don’t, please explain why not.

F-Staff-168
Ref: Exh F/Tab 4/Sch 1 p. 2

At the above reference, it is stated that:

Having clear and visible values helps Hydro One in its decision-making processes. For example, the value of “Win as One” fosters a shared understanding within the company that a successful decision is one that leads to an outcome that considers the needs of Hydro One, its customer, its employees, and its shareholders.

a) Please explain how Hydro One determines whether or not a decision is successful.
b) Please state how Hydro One would balance the needs of Hydro One, its customers, its employees, and its shareholders in making a determination that a decision is successful.

F-Staff-169
Ref: Exh F/Tab 4/Sch 1 p. 2

At the above reference, it is stated that:

Values help communicate to key stakeholders, such as shareholders and customers, the identity of the company and what it is about. Having a clearly articulated and specific set of core values provides a competitive advantage to Hydro One and assists it in working with these and other stakeholders.

a) Please state what is meant by the competitive advantage that Hydro One has as a result of its core values.
b) Please provide some examples of how this has worked to benefit Hydro One.

F-Staff-170
Ref: Exh F/Tab 4/Sch 1 p. 12

At the above reference, it is stated that:

To further improve resource planning, in 2019, Hydro One launched the Operational Workforce Planning initiative to ensure it has the right workforce to support the business strategy and current and future work program requirements. The purpose of the program is to enhance short and long-term headcount management efforts and to provide insights on current and future talent requirements.

a) Please discuss how and why Hydro One decided to launch this initiative and to what extent it was developed within Hydro One as compared to being an approach already in use in other organizations which was adapted to Hydro One.
b) Please state whether any significant cost savings are expected to arise from this initiative and if so what they are and when they are expected, including the impact on FTEs in 2019 and going forward.

F-Staff-171
Ref: (1) Exh F/Tab 1/Sch 1 p. 3 Table 1,
(2) Exh F/Tab 4/ Sch 1 p. 13 Table 2,
(3) Exh F/Tab 1/Sch 2/Attachment 1/p. 5.

At the first reference above, Hydro One's Total Transmission OM&A expenses are shown as decreasing from $385.0 million in 2017 to $375.8 million in the 2020 Test Year, which represents a decrease of over 2%

At the second reference above, Hydro One’s Grand Total FTEs are shown as increasing in the same period from 8,146 to 9,146, an increase of over 12%.

At the third noted reference Appendix 2-L “Recoverable OM&A Cost Per Customer and per FTE.” is shown.

a) Please update Appendix 2-L to reflect both 2017 and 2018 OEB-approved FTEs. If these numbers are not available, please provide an estimate.

b) In general, OEB staff notes that OM&A is decreasing, while the number of FTEs is increasing. Please confirm and explain the following movements in OM&A and FTEs in the table below:

	2019 forecast over 2018 actual	2020 forecast over 2019 forecast		2020 forecast over 2018 actual	2020 forecast over 2018 OEB approved
OM&A	-14.9%	5.4%		-10.3%	-4.7%
FTEs	9.3%	-0.8%		8.5%	n/a

F-Staff-172
Ref: Exh F/Tab 4/ Sch 1 p. 13 Table 2 and EB-2017-0049 Exh C1/Tab 2/Sch 1, p. 9 Table 1.

At the first reference above, Hydro One’s Full Time Equivalents (FTE), 2017 to 2022 are shown as increasing from 8,146 to 9,146, an increase of over 12%. At the second reference above it is stated that “Table 1 illustrates the forecast FTEs for 2017 to 2022. Total Regular FTEs and total Networks FTEs in 2022 are expected to be 2.0% and 1.3% lower respectively than in 2017.” FTE numbers decrease from 8,581 in 2017 to 8,467 in 2022.

a) Please reconcile the FTE numbers in these two tables and explain the shift to a 12% increase in the transmission application from a 2% decrease in the distribution application.

F-Staff-173
Ref: Exh F/Tab 4/ Sch 1 p. 37 Table 8.

Table 8 provides “Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median.” This table shows that while

Hydro One improved in the 2008 to 2017 period by 5%, it worsened by 2% in the more recent 2013 to 2017 period.

a) Please discuss the reasons for the deterioration in the 2013 to 2017 period.

F-Staff-174
Ref: Exh F/Tab 3/Sch 1 p. 2

At the above reference, it is stated that: "Hydro One relies on two main outsourcing arrangements in the operation of its businesses, one with Inergi LP ("Inergi") and another with Brookfield Asset Management."

a) Please state the percentage of Hydro One's total outsourcing dollars spent that are encompassed by these two agreements.
b) Please show the impact of the total outsourcing dollars on the 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital.

F-Staff-175
Ref: Exh F/Tab 3/Sch 1 pp. 3-4

At the above reference, it is stated that the Inergi Agreement provides for optional benchmarking reviews of fees by an independent third party, but that to date Hydro One has not exercised its option to benchmark. This decision is stated as being largely attributable to the integration of the customer service operations and the re-negotiation of information technology and supply chain SOWs (Statement of Work) which financially make up the majority of the contract at approximately 88%.

a) Please explain why Hydro One did not have the fees benchmarked before undertaking the above two referenced steps.

F-Staff-176
Ref: Exh F/Tab 3/Sch 1 pp. 4-5

At the above reference, Table 1 provides Inergi's 2018 performance. It is stated that service quality is measured using defined service levels or Performance Indicators (PIs) and client satisfaction surveys and that the PIs are adjusted upwards annually, where applicable to drive continuous improvement.

a) Please describe the process by which the PIs are adjusted annually and how it is determined whether or not such adjustments are applicable.
b) Please discuss why Inergi only met 82% of its performance targets in 2018 and whether or not Hydro One viewed this as an acceptable level of performance. If Hydro One considered this an acceptable performance level, please explain why. If not, please describe any actions that will be taken in response to it.

F-Staff-177
Ref: Exh F/Tab 3/Sch 1 p. 8

At the above reference, it is stated with respect to the BGIS contract fees that:

BGIS receives annual management and administrative fees which include overhead and profit. This fee is adjusted annually for inflation in accordance with the consumer price index and as necessary in the event of material changes in the scope of the work. Built into the fee structure are incentives for BGIS to achieve cost savings….

Hydro One may request third party benchmarking after three years and every two years thereafter, with a "benchmark fee adjustment", if the aggregate fees are above five percent of the target results….

The BGIS Agreement provides for Critical Service Levels ("CSL"), Key Performance Indicator ("KPI") measures and critical deliverables. BGIS's services are measured and reviewed regularly (monthly, quarterly and annually) to validate achievement of KPIs.

The CSLs and KPIs are based on the nature of the services provided by BGIS and set forth both expected and minimally accepted service levels. If BGIS fails to meet specific criteria, there are adverse financial consequences for BGIS.

a) Please describe how incentives for BGIS to achieve cost savings are built into the fee structure. Please discuss what the adverse financial consequences for BGIS would be if BGIS fails to meet the specific criteria.
b) Please state whether or not Hydro One has requested third party benchmarking to date with respect to this contract and whether or not it has any plans to do so in the future. Please also explain why or why not this is the case.

F-Staff-178

Ref: (1) Exh F-4-1 Attachment 1 *Hydro One Inc. Management Compensation Benchmarking Study February 2019*

(2) EB-2017-0049 *Management and Non-Represented Role Benchmarking and 2018 Compensation Structure Recommendations* Filed: 2018-04-20,

Exh C1-2-1 Attachment 1 *Hydro One Executive Compensation Benchmarking* Updated: 2017-06-07,

Exh C1-2-1 Attachment 2 *Hydro One Competitive Compensation Review* Updated: 2017-06-07.

The first reference above is a compensation study prepared by Willis Towers Watson for the current application.

The second reference lists three compensation studies prepared by either Willis Towers Watson or Towers Watson for Hydro One's recent distribution rates application.

a) Please state how the study in the current application relates to the three studies filed in the previous application.
b) Please provide a table summarizing and comparing the key recommendations of the current study with those in the previous studies. Please include an explanation for any changes between the recommendations in the current study and those in the previous application, particularly with respect to recommended levels of compensation.
c) Please describe how Hydro One's consideration of the above referenced studies impacted the requested 2020 test year revenue requirement, including the impacts on both 2020 OM&A and 2020 capital.

F-Staff-179

Ref: Exh F/Tab 6/Sch 1/Attachment 2

OEB Staff seeks additional information in order to better understand the growth in capital cost resulting from the forecasted capital additions during the term of the Custom IR plan.

a) Please provide the depreciation expenses associated with the gross plant additions that Hydro One proposes to make in each year of the Custom IR term (e.g., depreciation expense for each of the 2020, 2021, and 2022 plant additions) by completing the table below.

Depreciation Expenses from Gross Capital Additions

Year Addition Placed Into Service	2020	2021	2022
2020			
2021			
2022			

b) Please confirm that Hydro One has not requested accelerated depreciation of these assets, and that, for regulatory rate-making purposes, the half-year rule would apply to these plant additions for the year in which they are placed in service.

F-Staff-180

Ref: Exh F/Tab 2/Sch 2/p. 4 and Exh A/Tab 3/Sch 1/p. 25

At the first reference above, the following is stated:

The changes in the Hydro One Transmission portion of CCF&S costs are largely due to the same factors noted above for changes in total CCF&S costs. The allocation of cost to transmission in the 2020 test year is lower than 2015 actuals despite inflationary pressures. This is the result of Hydro One's application of 'transformation costs' to pre-IPO levels, Bill 2 legislation and corporate cost reductions previously described in Exhibit F, Tab 2, Schedule 1, page 1. Table 3, below, shows the detailed breakdown between labour, non-labour and where appropriate, other costs included in the CCF&S costs for the Bridge and Test period.

At the second reference above, the following is stated:

In developing its Investment Plan, Hydro One utilized the Ontario Consumer Price Index ("CPI") for its assumptions about inflation. A CPI of 2% was assumed over the planning period…

OEB staff notes that Hydro One refers to inflationary pressures when explaining variances in certain OM&A costs.

OEB staff further notes that the inflation rate calculated by the OEB for rate changes effective in 2019 is 1.5%.[9]

[9] 2019 EDR Webpage November 23, 2018 Reference – "…the OEB has calculated the value of the inflation factor for incentive rate setting under the Price Cap IR and Annual Index plans, for rate changes effective in 2019, to be 1.5%..."

a) Has Hydro One used a 2% inflation rate to budget OM&A expenses for the 2020 test year? If yes, please explain including why Hydro One didn't used the OEB inflation rate referenced above. If no, please explain what inflation rate Hydro One has used and why.

F-Staff-181
Ref: Exh A/Tab 3/Sch 1/p. 40

At the reference above, the following is stated:

A summary of forecast OM&A expenses for the 2020 test year is provided in Exhibit F, Tab 1, Schedule 1. These amounts have been reduced by the OM&A productivity savings outlined in Table 2 of this Exhibit. As shown in Table 9, 2020 OM&A expenses are expected to be $18.5 million lower (4.7%) than the 2018 OEB-approved (plan) funding envelope and are $34 million lower than what they would be if 2018 OEB-approved funding levels were increased at a 2% rate of inflation in 2019 and 2020

a) Please provide a revised calculation of 2020 OM&A expenses if the OEB inflation rate of 1.5% is used in place of the 2% inflation rate assumed by Hydro One.

F-Staff-182
Ref: Exh A/Tab 3/Sch 1/p. 40

At the reference above, the following is stated:

These reductions were achieved primarily through a reduction in vacancies and by limiting consulting and contract engagements to critical functions, which also assist in strengthening and building internal capabilities.

a) Please provide the impact of these actions on FTEs and compensation (both capital and OM&A) in 2020 as well as the impact on the 2020 revenue requirement.

F-Staff-183
Ref: Exh A/Tab 3/Sch 1/p. 40 and Exh A/Tab 3/Sch 1/p. 3

At the first reference above, the following is stated:

Hydro One expects safety and reliability performance to be maintained over the TSP planning period at the proposed funding levels.

At the second reference above, the following is stated:

Hydro One's plan will address critical safety and environmental risks in its system. It will improve reliability performance by 13% to return to the top quartile performance that Hydro One's transmission customers are expecting.

a) Please reconcile the two statements above with respect to the stated intention to maintain reliability in the first and to increase it by 13% in the second.

b) Please provide more detail as to why a top quartile reliability performance is needed, versus the status quo second quartile reliability performance.

c) Please discuss the basis for Hydro One's view that its customers are expecting it to return to top quartile performance

d) Please quantify the impact on the 2020 revenue requirement, including the impacts on both OM&A and capital, if Hydro One was to remain at its present level of reliability performance.

F-Staff-184
<u>Ref: Exh A/Tab 3/Sch 1/p. 40.</u>

At the reference above, the following is stated:

2019 OM&A expenditures are lower than the proposed test year OM&A as a result of the need to align to the funding envelope afforded in Hydro One's 2019 transmission revenue cap adjustment application (EB-2018-0130). This maintenance reduction has included reductions in activities including a one year extension of planned maintenance and asset condition assessments and represents a managed increase in asset risk that may manifest in terms of increased corrective/demand failures and/or reduced asset useful life but can be contained with a one year reduction in work and will be managed and mitigated in future years.

a) Please provide further explanation as to why the 2019 maintenance reduction, including a one year extension of planned maintenance and asset condition assessments, represented a managed increase in asset risk.

b) Please provide further explanation as to why Hydro One is of the view that this reduction may manifest in terms of increased corrective/demand failures and/or reduced asset useful life.

c) Please quantify and explain the impact of the 2019 extension of planned maintenance and asset condition assessments on both the 2019 and 2020 revenue requirements, including the impacts on both OM&A and capital.

d) Please provide further explanation as to why the 2019 extension of planned maintenance and asset condition assessments could not be repeated in 2020.

e) Please provide the impact on the 2020 revenue requirement, including the impacts on both OM&A and capital If the 2019 extension of planned maintenance and asset condition assessments was repeated in 2020,

F-Staff-185

Ref: Exh A/Tab 3/Sch 1 and Exh F/Tab 1/Sch 1.

At the references above, Hydro One's derivation of its 2020 level of requested OM&A is discussed.

a) Please provide a summary table quantifying the impacts on the 2020 revenue requirement, including the impacts on both OM&A and capital, due to Hydro One's efforts, as noted in the references above, in the areas listed below:

    i. The management of maintenance cycles
    ii. The company-wide exercise undertaken by Hydro One to review and reduce corporate common costs as primarily achieved by:
        1. The reduction in vacancies
        2. The limiting of consulting and contract engagements to critical functions
    iii. Sustained productivity gains
    iv. The renegotiation of the Inergi outsourcing agreement

F-Staff-186

Ref: Exh F/Tab 1/Sch 1/p. 4

At the above reference the following is stated:

The proposed budget in the 2020 test year is $13.6 million more compared to the 2019 bridge year, but it is in-line with average historical levels. This increase is necessary to meet the legislated deadlines associated with the PCB program, fund planned transformer overhauls, support previously deferred preventative maintenance for station assets, and to address the backlog in overhead lines and component inspections and assessments. As highlighted earlier, the 2019 bridge year forecast for Sustainment OM&A is lower than historical levels partially as a result of a one-time extension of Hydro One's planned asset maintenance cycles. This includes fewer planned demand and corrective expenditures, extension of the PCB testing and retrofill program, deferral of overhead transmission line preventive maintenance and deferral of vegetation management on select 115kV circuits.

a) Please explain why the "previously deferred preventative maintenance for station assets" and the addressing of the "backlog in overhead lines and component inspections and assessments" is appropriate to be reflected in the 2020 test year, when Hydro One made a decision to defer these items in 2019.

F-Staff-187
<u>Ref: Exh A/Tab 3/Schedule 1/pp. 41-42, Table 9</u>

At the above reference the following is stated:

The "Plan" values shown in Table 9 at an individual investment category level for the historical and bridge years reflect the funding levels previously proposed by Hydro One in applications to the OEB for the applicable years. Values at the category level have not been adjusted in response to reductions to the overall OM&A expenditure levels approved in the applicable OEB decisions as the OEB's findings were at an envelope level. As such, OEB-reductions are included as a separate line item under "Adjustments" and are reflected in the total transmission OM&A "Plan" values at envelope level for the historical and bridge years. For further details, please see Exhibit F, Tab 1, Schedule 1.

a) Please provide further explanation as to why the envelope adjustments that occurred in the 2015, 2016, 2017, and 2018 historical years could not be applied to the main components of OM&A in Table 9.

F-Staff-188
<u>Ref: Exh F/Tab 1/Sch 6/p. 2, Table 1 and p. 7.</u>

At the first reference above, Customer Care OM&A is shown as increasing from a 2018 "Plan" level of $3.9 million to an "Actual" level of $11.0 million

At the second reference above, the following is stated:

Over the 2015 to 2018 period, Customer Care OM&A expenditures trended upwards mainly due to the increased focus on large transmission customers, as well as increased costs related to detailed customer surveys which were centralized and included in this category level.

a) Please explain the differential between the 2018 "Plan" and "Actual" levels noted above
b) Please provide further explanation as to why an increased focus on large transmission customers, as well as customer surveys, as discussed in the second reference caused Customer Care OM&A expenditures to trend upwards over the 2015 to 2018 period.

F-Staff-189
<u>Exh F/Tab 2/Sch 2/p. 15 and Exh A/Tab 3/Sch 1/p. 40</u>

At the first reference above, the following is stated:

Higher costs in 2018 and forecasted for 2019 and 2020 are due to a renewed investment in human resources talent. In order to meet new demands and greater expectations for human resource products and services, Hydro One has recruited additional external resources that will enable the function to deliver on what is needed to support the execution of the overall business strategy.

At the second reference above, the following is stated:

… OM&A reductions will be achieved through operating efficiencies, particularly the management of maintenance cycles, and a company-wide exercise undertaken by Hydro One to review and reduce corporate common costs. The review resulted in a significant commitment by business units to reduce corporate costs across the organization. These reductions were achieved primarily through a reduction in vacancies and by limiting consulting and contract engagements to critical functions, which also assist in strengthening and building internal capabilities.

a) Please reconcile Hydro One's statement in the first reference that it has "recruited additional external resources" with its statement in the second reference that it is "limiting consulting and contract engagements to critical functions."

F-Staff-190
Ref: Exh F/Tab 2/Sch 2/p. 35.

At the above reference, the following is stated:

Capitalized overheads represent the portion of allocated Common Corporate and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and the budgets of other lines of business. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized OM&A costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization studies performed by Black & Veatch, as described in Exhibit C, Tab 8, Schedule 2. As the capital work program increases, more overheads are capitalized.

It is OEB staff's understanding from the above that both the OM&A and capital components to Common Corporate Costs and Other Costs are recorded in Hydro One's OM&A. A calculation is then performed to remove the amounts that should be capitalized and a reduction is made to Common Corporate Costs and Other Costs through the line item "Other OM&A", representing a credit to OM&A.

a) Please state whether OEB staff's understanding is correct. If this is not the case, please explain.

b) If OEB staff's understanding is correct, please explain why the amounts recorded in Common Corporate Costs and Other Costs reflect a two-step process (i.e. step #1 record all costs and step #2 remove capitalized components), rather than simply recording directly only the amounts related to OM&A in one step.

F-Staff-191
Ref: Exh F/Tab 2/Sch 1/p. 2, Table 2

At the above noted reference, the 2020 "Other OM&A" credit balance of $138.1 million is shown as an offset to the 2020 balance of $30.3 million. As well, a footnote to this table shows that OEB-directed reductions for compensation are reflected in this line item, including the 2017 and 2018 pension adjustment.

a) Please normalize the 2018 plan amount for "Other OM&A" to reflect the removal of "OEB-directed reductions for compensation" and show the percentage change when compared to the 2020 amount of "Other OM&A". Please provide an explanation for the change between the 2020 amount and the normalized 2018 plan amount.

F-Staff-192
Ref: Exh F/Tab 2/Sch 2/p. 35/ Table 15 and Exh F/Tab 1/Sch 3/p. 10/ Table 3.

At the first reference above, Table 15, which is entitled "Transmission Other OM&A" includes a category "Environmental Provision" which shows a credit balance of $12.6 million. This is a $2.6 million increase in the credit balance from the 2018 Plan level or a 26.0% increase to $12.6 million in 2020.

At the second reference above, Table 3, which is entitled "Environmental Management OM&A," the balance for 2020 is $22.1 million.

a) Please explain the difference between these two numbers.

F-Staff-193
Ref: Exh F/Tab 2/Sch 6/p. 4/ Table 3 and Exh F/Tab 2/Sch 6/Attachment 1/"Black and Veatch Report.

a) Please explain how the amounts in the "Transmission" column of Table 3 are derived.

b) Please state whether any updates to the 2019 Black & Veatch Report would need to be made to reflect the impact of the following two subsequent events:

   a. Bill 2 and the February 21, 2019 Directive
   b. EB-2017-0049 Hydro One Distribution Decision and Order March 7, 2019

c) Please describe the updates made to the 2019 Black & Veatch Report since the last report was issued December 21, 2016, and state whether any of these changes would materially impact the 2020 revenue requirement.

F-Staff-194
Ref: Exh F/Tab 4/Sch 1/p. 5

At the above noted reference, the following is stated:

> Contract staff are individuals engaged as independent contractors, and are not on Hydro One's payroll. Contract staff are retained for their particular skill sets on projects, or to perform other work that is not of an ongoing nature. They are engaged by Hydro One for varying amounts of time and paid varying wages commensurate with their skill sets and the market rate for that skill. Contract staff are tracked by work programs or activities and not by headcount. Where applicable, the use of contract staff is governed by the terms of the collective agreements between Hydro One and its respective unions.

a) Please confirm that Contract Staff are not included in Hydro One's overall headcount.

b) Please provide the Contract Staff data as tracked by work programs and activities.

c) Please provide data to indicate how much Hydro One is spending on Contract Staff. If the data is not available, please explain why not.

d) How does Hydro One ensure that it is paying Contract Staff market rates for the skills procured?

e) What percentage of Contract Staff are former employees of Hydro One?

F-Staff-195
Ref: Exh F/Tab 4/Sch 1/p. 13

At the above noted reference, Hydro One has provided "Table 2: Full Time Equivalents (FTE), 2017 to 2022."

OEB staff notes that the Total Regular FTEs for 2017 in this table are listed at 5,726 FTEs. However, OEB staff notes that when the FTE components in this table for 2017 are added together, the Total Regular FTEs for 2017 is 5,304 FTEs.

a) Please comment on this discrepancy and if necessary, update "Table 2: Full Time Equivalents (FTE), 2017 to 2022" with the correct amount of Total Regular FTEs for 2017.

F-Staff-196
Ref: Exh F/Tab 4/Sch 1/p. 13

At the above noted reference, Hydro One has provided "Table 2: Full Time Equivalents (FTE), 2017 to 2022."

Hydro One stated that Table 2 illustrates the historical (2017 and 2018) and forecasted (2019-2022) FTEs. Hydro One indicated that total regular and non-regular FTEs increase over this period primarily due to seven items which were listed.

a) Please quantify the impact between 2017 and 2022 on total FTEs and total compensation for each of the seven items. Please separate the impact between Transmission, Distribution, and Other.

F-Staff-197
Ref:
(1) Exh F/Tab 4/Sch 1/p. 23
(2) Exh F/Tab 4/Sch 1/p. 24
(3) Exh F/Tab 4/Sch 1/p. 38

Hydro One stated the following at the above noted first reference:

> …The 2017 Mercer Total Compensation Study described in greater detail in Section 7.7.3 of this Exhibit shows that MCP total compensation is positioned 1% above market median…

However, at the above noted second reference, "Table 4: Willis Towers Watson, Salary Structure Positioning to Market Median" shows that "Target Total Direct Compensation" is 3% above the market median on an "Overall" basis.

At the third reference, the following table is shown – “Table 8: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median.” This shows that overall compensation (Management, Society, PWU) is 12% above the market median.

a) Please explain the difference between the first reference, which states that total compensation is positioned 1% above market median, and the second reference which shows a level of 3% above market median.

b) Please explain to what extent Hydro One is making efforts to bring its compensation more in line with the comparators.

c) Please provide a list of all types of compensation (i.e. salary, overtime, share grant, LTIP, etc.) that were paid in 2018 that: i) were included in the study, and ii) were not included in the study.

d) Are there any additional types of compensation (e.g. lump sum payments) that will be paid in 2020 that were not in 2018?

F-Staff-198
<u>Ref: Exh F/Tab 4/Sch 1/p. 32</u>

Hydro One stated the following at the above noted first reference:

> Consistent with the OEB’s findings in EB-2016-0160 and the compensation evidence filed in Hydro One’s 2018-2022 Distribution Custom IR application (EB-2017-0049), Attachment 5 to this Exhibit provides actual total compensation cost for Hydro One Networks and for both the distribution and transmission businesses for 2014 to 2018 and forecast total compensation cost for the years 2019 to 2022. While the Transmission work program is growing by approximately 26% between 2019 and 2022, Transmission related compensation costs are growing by only 12% or 4% per annum.

a) Please provide a detailed explanation as to how with the transmission work program growing by 26% between 2019 and 2022, transmission related compensation costs are growing by only 12%. Please include in the discussion any impacts of changes in allocations between the transmission and distribution operations of Hydro One, as well as overhead allocations from OM&A to the capital program.

F-Staff-199
Ref: Exh F/Tab 4/Sch 1/p. 34, 35

At the above noted reference, Hydro One describes how its requested executive compensation and board of director costs are in compliance with Bill 2 and the February 21, 2019 Directive.

a) Please confirm that no further adjustments to Hydro One's requested executive compensation and board of director costs are required to ensure compliance with Bill 2 and the February 21, 2019 Directive as well as the OEB's EB-2017-0049 Decision and Order..

F-Staff-200
Ref: Exh F/Tab 1/Sch 1/p. 7

At the above noted reference, Hydro One stated the following:

> 2018 actuals are lower than the 2018 plan and 2017 actual expenditure, mainly due lower Operations staff costs (i.e., lower pension burdens, adjustments based on average vacancy rates, and applied recoveries).

a) Please provide Hydro One's actual vacancy rate for each year between 2014 and 2018.
b) Please provide the forecast vacancy rate for 2020, and the basis for the forecast.
c) Please confirm that Hydro One has built into its budget for 2020 its forecast vacancy rate for 2020.
d) If (c) is confirmed, please explain how Hydro One has translated the forecast vacancy rate into a budgeted number.
e) If (c) is not, please explain why not.

F-Staff-201
Ref: Exh F/Tab 1/Sch 7/p. Page 4
Exh B/Tab 1/Sch 1/TSP Section 1.6, p.7

At the above noted reference, Hydro One stated the following:

> Hydro One's aim is to execute its annual O&M work strategy at a lower cost relative to historical costs through improved productivity…

At the above noted second reference, Hydro One stated that $22 million of OM&A productivity savings have been estimated for 2020.

a) Please confirm that the above $22 million of forecasted OM&A productivity savings have been incorporated into Hydro One's requested OM&A for 2020 of $375.8 million. If this is not the case, please explain.

b) Are the forecasted productivity savings a key factor in keeping the 2020 OM&A at the requested level of $375.8 million? Please explain.

F-Staff-202

Ref: (1) Exh F/Tab5/Sch 1 pp.1-2
(2) EB-2016-0160, Sept 27, 2017 Decision and Order p.81

At the first reference above, Hydro One has stated that it is proposing to recover its pension costs on a cash basis.

At the second reference above, the OEB ordered that if Hydro One proposes to continue using the cash method as the basis for recovering its pension costs beyond December 31, 2018, then in its next transmission revenue requirement proceeding, Hydro One must provide evidence that addresses the principles, practices and policy determinations in accordance with the provisions

In its September 14, 2017 Report on the Regulatory Treatment of Pension and OPEB costs (OEB Report), the OEB indicated that utilities proposing to set rates using a method other than accrual must support such a proposal with evidence, giving consideration to factors such as providing value to customers and assuring fairness to both present and future ratepayers, and the principles and practices enunciated in the OEB Report.

a) In accordance with the OEB Report, please provide evidence that supports the appropriateness of Hydro One's use of the cash method to recover its pension costs. Please ensure that the evidence provided addresses the required areas as specified in OEB Report.

b) In indicating that the cash method results in lower costs being recovered through rates, Hydro One, has not provided any analysis to support this statement. To that end, please prepare an analysis similar to the one provided for OPEBs in Table 3 of Exhibit F/Tab5/Schedule1, comparing on a historical basis, the cash amount recovered in rates and the accrual expense related to Hydro One's annual pension obligations.

F-Staff-203

Ref: (1) Exh F/Tab 5/Sch 1/Attachment 1 p 15 of 61
(2) Exh F/Tab 5/Sch 1/Table 2

At the first reference above , Hydro One has provided the pension valuation that underpins the pension cash contributions for the bridge and test years.

At the second reference above, Hydro One has presented its pension contributions for 2020 in Table 2, broken out between capital and OM&A.

a) For the bridge year 2019, please confirm if Hydro One chose to take a pension contribution holiday and whether it filed the related cost certificate within the legislated deadline of the Pension Benefits Act
b) In Table 2 of Ex F-5-1, Hydro One presents total pension contributions for the combined company of $78 million. Please explain the discrepancy compared to the total pension contributions for 2020 as presented in Section 3 of the pension valuation ($69 million).
c) If $69 million is in fact the correct contribution amount, then please prepare Table 2 of Ex F-5-1 with the correct amounts and allocations between the Transmission and Distribution businesses.
d) As part of the current application, Hydro One has capitalized amounts related to pension costs for the years 2021 and 2022. Please provide the amount of pension costs being capitalized for each of these years.
e) Please explain what underpins the pension costs being capitalized for those years. If they are an estimate, please explain the basis for this estimate.
f) Please explain where the variance is captured between what Hydro One proposes as the capital component of its pension costs compared to what it actually capitalizes in respect to its pension costs.

F-Staff-204
Ref: Exh F/Tab 5/Sch 1 pp. 5-6

At the above reference, Hydro One describes the uncertainty around its ability to take a pension contribution holiday in 2020, and that it almost certain that it will not be able to take a contribution holiday in 2021 and 2022 due to the new funding rules. Hydro One further proposes that given the uncertainty, it will track the difference between pension costs recovered in rates and actual pension payments made to the plan.

a) Is Hydro One proposing to track the difference in its existing Pension Differential variance account?
b) If so, the current Pension Differential account only tracks the difference related to the OM&A component pension costs. Given that pension costs have both a capital and OM&A component, how is Hydro One proposing to track the difference impacting the capitalized component?
c) If Hydro One is in fact proposing a new account for this purpose, then please indicate this intention and file a draft accounting order.

F-Staff-205
Ref: Exh F/Tab 5/Sch 1 p. 9

At the above reference, Hydro One indicates that it is seeking to recover its OPEB costs on an accrual basis and presents a table that breaks-out between capital and OM&A, the amount that is being sought in respect to OPEB costs for 2020.

a) Please provide the OPEB valuation that support the amount for 2020.
b) Please provide the amounts in respect to OPEB costs that are being capitalized in this application for 2021 and 2022.
c) What is the basis for the amounts being capitalized in each of these years?
d) In Table 3, Hydro One provides a historical summary of OPEB costs it has recovered in rates (on an accrual basis) compared to the related cash payments for the same period. The analysis indicates that Hydro One has historically over-

collected with respect to its OPEB costs. Please explain how these over-collections have been used.

F-Staff-206

Ref: Exh F/Tab 5/Sch 1 p. 10

At the above reference, Hydro One describes the three potential outcomes with respect to its proposals to address the new US GAAP accounting standard that will limit how much of its OPEB costs it is able to capitalize.

a) In regard to the OEB approving the continuance of the deferral account option. Please confirm that the intention of the account will be to continue to only capture the portion of the OPEB costs that can no longer be capitalized? Or is the intention to also include a return on rate base component that would have been earned on these amounts had they had been included in rate base.
b) In regard to the OEB disallowing both the capitalization option and the continued use of the deferral account, how will the amounts already included in the account for 2018 be dealt with? Will Hydro One then be asking for disposition of the account balance as at December 31, 2018, or will it defer disposition to a future period?

F-Staff-207

Ref: Exh F/Tab 7/Sch 2/Attachment 1

At the above reference, Hydro One provides its detailed regulatory tax calculations for the period 2019-2022, including the sharing of the tax benefits that resulted from Hydro One's IPO. Hydro One shares those benefits based on a ratio that allocates 63.5% of the benefits in favour of the shareholder.

In the November 9, 2017 Decision and Order for EB-2016-0160 (H1 Tx), the OEB multiplied the benefits follow costs allocation factor in favour of shareholders by the

Grossed Up Regulatory Taxes for 2017 and 2018 respectively in order to arrive at the regulatory taxes included in the revenue requirement for each year. The Grossed Up Regulatory Tax balance that was used in that calculation for each year represented the regulatory taxes that would have been included in the revenue requirement had the tax benefits from the IPO been allocated 100% in favour of the shareholder. This calculation that was used to arrive at the final regulatory tax balance for both 2017 and 2018 was not contested and the resulting regulatory taxes were included in rates approved for the respective years.

a) It appears that Hydro One has deviated from the above approved methodology within its tax calculations in the current proceeding, please explain why that is the case and why Hydro One's current proposal with respect to calculating the allocation of the tax benefits is more appropriate.
b) Please provide a table that compares annually, the tax benefits allocated to the ratepayers/shareholder under Hydro One's current proposal within this application versus the methodology used in the EB-2016-0160 Decision and Order (as described above).

F-Staff-208

<u>Ref: Exh F/Tab 7/Sch 2/Attachment 2</u>

At the above reference, Hydro One provides its CCA continuity schedule for the period 2019-2022

The Government of Canada's 2018 Fall Economic Statement was tabled on November 21, 2018.It proposes the following measures for certain eligible property acquired after November 20, 2018:

- Accelerated Investment Incentive – Providing an enhanced first-year allowance for certain eligible property that is subject to the Capital Cost Allowance (CCA) rules. In general, the incentive will be made up of two elements:
  - applying the prescribed CCA rate for a class to up to one-and-a-half times the net addition to the class for the year
  - suspending the existing CCA half-year rule (and equivalent rules for Canadian vessels and class 13 property).

- Full Expensing for Manufacturers and Processors – Allowing businesses to immediately write off the full cost of machinery and equipment used for the manufacturing or processing of goods (class 53).

- Full Expensing for Clean Energy Investments – Allowing businesses to immediately write off the full cost of specified clean energy equipment (classes 43.1 and 43.2).

The Federal Government's 2019 Budget, announced on March 19, 2019 confirmed the Government's intention to proceed with the above proposals.

a) Please state whether Hydro One has reflected the impact of the new accelerated CCA rules within its CCA calculations for the period 2019-2022 that are currently on the record of this proceeding.

b) If the accelerated CCA rules are not reflected, then please explain why this is the case. Please also provide updated detailed PILs calculations and supporting CCA tables for the period 2019-2022 that reflect the new accelerated CCA rules.

c) Since the accelerated CCA rules are effective from November 20, 2018, please confirm if Hydro One has prepared its 2018 corporate tax return using these new CCA rules. If not, please explain why that is the case.

d) Given that the approved 2018 and 2019 rates were underpinned by the old CCA rules, how is Hydro One planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the difference between the PILs amounts included in rates for those years and the PILS amounts that would have been included in rates had they been based on the new accelerated CCA rules.

e) Please provide the calculations for 2018 and 2019 revenue requirement impact had the PILs for those years been calculated using the new accelerated CCA rules.

f) If Hydro One is not planning to make ratepayers whole with respect to the 2018 and 2019 revenue requirement impact associated with the change in CCA rules, then please explain why such an approach would be appropriate.

g) How does Hydro One intend to treat expenditures made under long-term capital projects based on the new rules? For example, if Hydro One had undertook and incurred expenditure for a capital project that commenced before the new rules took effect (and continued to carry-on after the new rules took effect), will the expenditures incurred before and after the effective date of the new rules be treated differently for this project for purposes of calculating CCA once the related asset is put into service?

F-Staff-209

Ref: Exh F/Tab 7/Sch 2/Attachment 2A

At the above reference, Hydro One provides a reconciliation of its accounting to tax additions for the period 2020-2022

a) Please explain the nature of the line item "asset removal" and why it is part of this reconciliation.

F-Staff-210

Ref: Exh F/Tab 7/Sch 1

Within the regulatory tax evidence that is filed for this proceeding, Hydro One has not provided any details related to its recently filed 2018 corporate tax return.

a) Please provide Schedules 1, 4, 8 and 13 from the 2018 corporate tax return.

F-Staff-211

Ref: Exh F/Tab 7/Sch 4/Table 2

At the above reference, Hydro One provides a summary of its historical and forecast property taxes.

a) There was a property tax adjustment of $12.1 million in 2017. Please explain why this adjustment appears to only be one-time in nature and has no impact on lowering property taxes for the future periods presented in the table?

F-Staff-212
Ref: Exh F/Tab 6/Sch 1

At the above reference, Hydro One discusses the depreciation it is seeking to recover over the term of its application and the related study that was undertaken to underpin the depreciation rates used.

a) If the depreciation rates used remained consistent with the ones approved by the OEB in Hydro One’s 2017-2018 transmission rates application, please recalculate what the depreciation expense would be annually over the term of the current application.
b) In Hydro One’s recent distribution rates application, the study that was undertaken to underpin the related depreciation rates was not used and the rates remained unchanged from what had been approved in the previous proceeding. Please explain why that was appropriate in the distribution rates proceeding but is not appropriate for the transmission rates proceeding?

EXHIBIT G – COST OF CAPITAL AND CAPITAL STRUCTURE

No interrogatories

EXHIBIT H - REGULATORY ACCOUNTS

H-Staff-213
Ref: Exh H/Tab 1/Sch 1/DVA Continuity Schedule (excel)

At the above reference, Hydro One has provided an excel version of its DVA continuity schedule.

a) Please prepare a DVA continuity schedule using the OEB approved DVA continuity schedule model for 2020 rate filers. This updated model is due to be released by the OEB in July 2019 and can be found on the OEB website.

H-Staff-214
Ref: Exh H/Tab 1/Sch 3/Table 1

At the above reference, Hydro One has provided a table that summarizes the request to dispose of $20.5 million with respect to its December 31, 2018 audited DVA account balances. Hydro One has requested disposition over a three-year period.

a) Given the relatively small balance being disposed of in this proceeding, please explain why Hydro One is seeking disposition over a three-year period as opposed the default one-year period that the OEB generally prescribes.

H-Staff-215
Ref: Exh H/Tab 1/Sch 1, p. 4

At the above reference, Hydro One describes the balance within its Excess Export Service Revenue account.

a) Please confirm that the $4.8 million balance within this account represents only the difference between forecast export service revenue approved for 2018 compared to actual 2018 (plus applicable interest)
b) Please provide the actual export service revenue for 2018.
a) Can the above actual number for 2018 be tied to Hydro One’s 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

H-Staff-216
Ref: Exh H/Tab 1/Sch 1, pp. 4-5

At the above reference, Hydro One describes the balance within its External Secondary Land Use Revenue account.

b) Please confirm that the $10.4 million balance within this account represents only the difference between forecast external secondary land use revenues approved by the OEB for 2018 compared to actual 2018 (plus applicable interest)
c) Please provide the actual external secondary land use revenues for 2018.
d) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

H-Staff-217
Ref: Exh H/Tab 1/Sch 1, pp. 5-6

At the above reference, Hydro One describes the balance within its External Station Maintenance, E&CS and Other External Revenue account.

a) Please confirm that the $4.5 million balance within this account represents only the difference between the OEB approved and actual external station maintenance, E&CS and other external revenues for 2018. (plus applicable interest)
b) Please provide the actual maintenance, E&CS and other revenues for 2018.
c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

H-Staff-218
Ref: Exh H/Tab 1/Sch 1, p. 6

At the above reference, Hydro One describes its Tax Rate Change account and has indicated that the balance is currently zero.

The Government of Canada's 2018 Fall Economic Statement proposed a number of tax changes related to CCA for certain eligible property acquired after November 20, 2018, which it further confirmed in its 2019 Budget.

a) Shouldn't amounts related to this tax change have been captured within this account for 2018? If so, then why is the account balance zero? If not, please explain why Hydro One believes that the impact of the aforementioned tax change should not be captured here.

H-Staff-219
<u>Ref: Exh H/Tab 1/Sch 1, pp. 7-8</u>

At the above reference, Hydro One describes the balance within its Pension Costs Differential Account.

a) Please confirm that the $4.5 million balance within this account represents only the difference between forecast approved and actual OM&A portion of pension contributions for 2018 (plus applicable interest)
b) Please provide both the pension contributions approved by the OEB for 2018 and the actual 2018 OM&A portion of pension contributions made by Hydro One.
c) Can the above actual number for 2018 be tied to Hydro One's 2018 audited financial statements? If so, please provide the reference. If not, please explain how this actual balance is derived and tracked by Hydro One.

H-Staff-220
<u>Ref: Exh H/Tab 1/Sch 1, pp. 13-14</u>

At the above reference, Hydro One describes its in service capital additions variance account.

a) Please provide a table that compares the approved in service capital additions for 2016, 2017 and 2018 compared to the actual in service capital additions for the same period.
b) Can the actual in service capital additions be reconciled to the audited financial statement of each respective year (i.e. the property plant, and equipment note)? If so, please provide the reference to each. If not, then please explain why the capital additions presented in the note disclosure referenced above would not tie to the in service additions used for the purposes of calculating a balance for this DVA account?

H-Staff-221

Ref: Exh H/Tab 1/Sch 1, p. 15
Exh H/Tab 1/Sch 2, pp. 12-14

At the above references, Hydro One describes its OPEB cost deferral account and its proposal to continue to capitalize the impacted OPEB costs for regulatory purposes.

a) In EB-2017-0338, Hydro One indicated that it expected the impact of the new ASU 2017-07 to be $11 million for 2018. However a balance of $22.5 million related to 2018 is currently being tracked in this account as at December 31, 2018. Please explain the significant difference compared to what was forecast in the EB-2017-0338 proceeding.
b) Can the $22.5 million be directly agreed to the underlying OPEB valuation for 2018? If not, please explain why.
c) Is there an estimated return component on the impacted costs that is also being tracked in this account? If so, how much of the account relates to this.
d) Why is Hydro One the only utility out of all of the US GAAP based utilities that are regulated by the OEB which is seeking this additional relief related to the adoption of ASU 2017-07.
e) If the OEB does not approve the continued capitalization of the impacted costs, nor does it approve the continued use of this deferral and variance account, how does Hydro One propose to deal with the disposition of the existing balance within this DVA account.
f) Please explain why Hydro One believes that rate payers would benefit from the continued capitalization of the impacted costs when they will end-up paying more

for these costs over the long-term (due to the return that will be attached to them).

g) Please provide Hydro One's forecast of the impacted costs for 2019, 2020, 2021, and 2022. What is the basis of the forecast for each year?

H-Staff-222

Ref: Exh H/Tab 1/Sch 2, pp. 9-12

At the above reference, Hydro One is proposing an alternate methodology to track its accrual vs cash differential related to its OPEB costs. It proposes an alternate methodology on the basis that it capitalizes a good portion of its OPEB costs, which is not contemplated by the methodology that is prescribed in the OEB's Report on the Regulatory Treatment of Pension and OPEB costs (the Report).

a) Although the Report indicates that a utility may propose an alternate methodology in the event that they capitalize a material portion of its OPEB costs, it further clarifies that there needs to be sufficient incremental value to warrant the added complexity of tracking amounts that are capitalized separately. To that end, please explain what Hydro One believes is the incremental value that is being achieved through its alternate methodology to warrant the additional complexity.
b) Hydro One's alternate methodology proposes to separately track the depreciation associated with capitalized OPEBs. How will the OEB be able to assess the prudence of such a balance when it will be subject to internal tracking by Hydro One and there will be no external support for the balance that the OEB can rely on?
c) Please clarify if the depreciation on capitalized OPEBs represents the depreciation on the cumulative capitalized OPEBs to date or the depreciation associated with OEPBs that have been capitalized from the effective date of the OEB's policy and forward. If it is only proposing to use the OPEB depreciation associated with OPEB costs that have been capitalized from the effective date of the OEB policy and forward, please explain why it believes that such treatment is appropriate and consistent with what the OEB Report is trying to achieve.
d) Based on Hydro One's alternate methodology, what would be the amount that is tracked in the tracking account and the related carrying charges be as at December 31, 2018. What would it be under the default methodology of the Report?

e) Please prepare a table that compares the accrual vs cash differential related to Hydro One's OPEBs for each year of the period 2019-2022 under the default approach that is prescribed by the Report compared to the alternate approach that Hydro One is proposing.
f) Under Hydro One's alternate approach, is it proposing to use the same interest rate as prescribed in the Report?

H-Staff-223
Ref: Exh H/Tab 1/Sch 2, p. 7

At the above reference, Hydro One is proposing a new earnings sharing mechanism, effective January 1, 2020, to record any over earnings realized during any year of the three-year term 2020-2022.

a) Please confirm that the basis of the ESM calculation will be the annual RRR 2.1.5.6 filing.
b) Please confirm that the account is asymmetrical in that it will only track over-earnings.

H-Staff-224
Ref: Exh H/Tab 1/Sch 2, p. 6

At the above reference, Hydro One is proposing to continue the in service capital additions variance account to record the net cumulative variance over 2020-2022 between OEB approved in service additions and actual.

a) It is not clear from the description provided whether the proposed new account will also capture the difference between approved and actual in-service additions for the bridge year 2019? If Hydro One is not proposing to include 2019 within this account, please explain why it feels that this would be appropriate.

EXHIBIT I: I1 – COST ALLOCATION TO UNIFORM TRANSMISSION RATE POOLS AND I2 RATE DESIGN FOR UNIFORM TRANSMISSION RATES

I-Staff-225
Ref: Exh I2/Tab 2/Sch 1, page 3 of 5

At the reference above, it is stated that:

Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years, such as inclusion of energy storage facilities.

The "Embedded Generation" section in the proposed 2020 Ontario Uniform Transmission Rate Schedules (Exhibit I2, Tab 6, Schedule 2, Attachment 1) has also been updated to align with the changes in billing demand for the Line and Transformation Connection services.

a) Please explain why the proposed changes to the definition of billing demand for the line and transformation connection services and the changes to the definition of embedded generation are necessary.
b) Please discuss whether or not there are costs shifted to other customers if existing customers with energy storage facilities and/or solar generators (the individual inverter unit capacity is one MW or higher) are continuing to be billed on a net load basis.
    i. If so, please quantify the shifted costs.
    ii. If not, why not.
c) Please explain when and how the original definitions were determined.
d) Did Hydro One consult customers with energy storage facilities and/or solar generators (the individual inverter unit capacity is 1 MW or higher) about the proposed changes? If so, what are the customers' feedback on the proposed changes? If not, why not?
e) Please estimate the bill impact for a customer with energy storage facilities or solar generators before and after the proposed changes using the proposed 2020 UTRs.

I-Staff-226
Ref: Exh I2/Tab 2/Sch 1/Attachment 1, page 1 of 11 and EB-2016-0160, Submissions of CME, pp. 26-27

At the first reference above, it is stated that:

In its October 11, 2017 Decision in Proceeding EB-2016-0160, the Board directed Hydro One to provide a report in its next Transmission rates application that addressed Canadian Manufacturers and Exporters' ("CME") concern about the Network Service Charge ("NSC") that applies to manufacturing or industrial customers who shift their operations to outside of the 7 AM to 7 PM timeframe when the system peak occurs after 7 PM. In response to the Board's Decision, this Exhibit examines the issue of modifying the existing NSC determinant to address CME's concern.

At the second reference above, it is stated that:

CME requests that the Board direct Hydro One to present a report in the next transmission case that addresses how the NSC determinant can be modified to ensure that manufacturing or industrial customers who shift their operations to outside of the 7 a.m. to 7 p.m. window, are not penalized when a system peak occurs after 7 p.m. We would request that the report consider:

i. Whether the NSC determinant should only be based on manufacturing and industrial customer's non-coincident monthly peak demand between 7 a.m. and 7 p.m. on IESO business days, and not in any way determined by the customer's demand that is coincident with the monthly system peak;
ii. Whether there should be a separate NSC determinant that is only applicable to manufacturing industrial customers; and
iii. Whether additional steps can be taken by Hydro One to assist manufacturing and industrial customers to ensure that they not inadvertently operate during a monthly system peak that occurs outside of 7 a.m. to 7 p.m.

a) Please state where in the current evidence Hydro One has addressed CME's concerns referenced above.
b) Please add, if any, the system peaks outside the 7AM to 7PM period for 2018 to Table 1 in Exhibit I2-2-1, Attachment 1.