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Hydro One Networks Inc.
Application for electricity transmission rates
for the period from January 1, 2020 to December 31, 2022

EB-2019-0082

Submission
of the
Vulnerable Energy Consumers Coalition
(VECC)

December 17, 2019

Vulnerable Energy Consumers Coalition

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Summary

Hydro One Transmission (H1TX) is seeking the following revenue requirement for the base 2020 year. VECC's proposed modifications to the 2020 revenue requirement and the formula to adjust it during the rate plan are summarized below the chart.

Table 1: Revenue Requirement ($ Millions)
Revised from Exhibit E, Tab 1, Schedule 1 – Table 1
Undertaking J8.5

Components	**2018**	**2019**	**2020** Blue Pages	**2020** Accelerated CCA	**2020** Actual Debt Issuances	**2020** Updated Pension Valuation	**2020 OPEB** ISA Assumption	**2020** Cost of Capital Parameters and Updated Inflation Factor	**2020** Cost of Capital Update
OM&A	394.3		375.8			(1.7)			374.1
Depreciation and Amortization	468.6		474.6			(0.1)	0.0		474.5
Income Taxes	57.2		48.3	(23.6)	0.1	1.3	0.1	(8.2)	18.1
Return on Capital	703.6		775.0		(8.3)	(0.2)	0.6	(31.5)	735.6
Total Revenue Requirement	**1,623.8**	**1,644.4**	**1,673.8**	**(23.6)**	**(8.2)**	**(0.7)**	**0.7**	**(39.7)**	**1,602.3**
Deduct External Revenues and Other [3]	(54.7)	(54.5)	(52.6)						(52.6)
Rates Revenue Requirement	**1,569.1**	**1,589.9**	**1,621.2**						**1,549.7**
Regulatory Deferral and Variance Accounts Disposition / Foregone Revenue	(58.4)	(37.6)	6.8						6.8
Rates Revenue Requirement (with Deferral and Variance	**1,510.7**	**1,552.3**	**1,628.0**						**1,556.6**

1. The Board should reduce Hydro One's capital investment program by approximately $100M per year in order to realign capital investment with past spending. This would result in a reduction of about $5 million in the test year revenue requirement due to lower in-service additions.

2. The Board should reduce the 2020 revenue requirement by $10 million in OM&A reductions to recognize Hydro One's continued above market compensation.

3. Hydro One should be directed to file evidence in its next rate rebasing application showing how its compensation relates to compensation in other sectors of the Ontario economy.

4. The revenue requirement adjustment formula should be amended to include a 0.30% stretch factor.

5. The revenue requirement formula should be amended to include a 0.31% C-factor stretch factor.

6. Future customer engagement should include an “account manager” report for all 63 LDCs connected to the transmission system.

7. The Scorecard should be amended to report outage statistics due to equipment failure.

8. Hydro One should be directed to, in its next cost of service application, propose ways of linking reliability outcomes to the rates or revenue requirement formula.

9. Should the Board choose not to continue the external revenue variance accounts then it should increase “other revenues” by at least $7M.

10. The Board should deny Hydro One’s request dispose of the balance associated with the LDC CDM and DR Variance Account for Transmission as currently calculated.

A: General

Has Hydro One responded appropriately to all relevant Ontario Energy Board (OEB) directions from previous proceedings?

Are the bill impacts resulting from Hydro One’s proposed revenue requirement reasonable?

Were Hydro One’s customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?

Is the proposed effective date of January 1, 2020 appropriate?

<u>OEB Directions</u>

A1. It is our view that Hydro One has responded to the Board’s directions from previous proceedings and in good faith. However, we do take issue with the substance of some of its responses, for example in the form of customer engagement. We discuss these issues in the body of our argument.

A2. Taken as a whole the bill impact to the Uniform Transmission Rates (UTR) are reasonable in that they are below the expected rate of inflation. Having said that it is our view that they might be reduced further based on our submissions.

<u>Customer Engagement</u>

A3. VECC believes Hydro One’s customer engagement was inadequate in two ways. First the Utility failed to engage directly local distribution companies (LDCs) end-use consumers. Rather its survey and engagement was limited to a sample of directly connected industrial customers and representatives of LDCs.

A4. The lack of end-use customer engagement relies upon a number of arguments. One was the assumption that LDC representatives have the same interest as their customers. We think this unlikely. While both LDC representatives and end-use customers are likely interested in reliable service, LDCs, who pass on the cost consequence of transmission costs are more likely to value reliability over the cost to achieve it. Hydro One surveying the chief or senior engineer of an LDC would no doubt find reliability a paramount concern and might consider that reliability at each of potentially multiple delivery points equally important. An end-use customer might only be concerned with the reliability of service and not whether connection redundancy was being challenged in order to deliver that outcome. In such circumstances the LDC might be inclined to weigh more heavily a marginal increase in reliability.

A5. Another argument given during the hearing for not directly engaging customers was that Hydro One would be "walking on the toes" of LDC by directly engaging "their" customers. This is nonsense. Hydro One does not "own" its customers any more than Toronto Hydro "owns" the customers it serves. Nothing precludes anyone from surveying an LDC's customers. In fact, in similar survey's carried out by LDC in support of their applications (and often by the same party -Innovative Research) LDCs are at pains to explain that not all outages are attributable to its distribution network. In any event the lack of directly engaging end-use customers is at odds with the Board's explicit comments in the prior transmission decision where it said: "[T]*he OEB does not consider the satisfaction level of directly connected local distributors to be indicative of their customers' level of satisfaction. Local distributors do not necessarily represent the interests of their customers on transmission issues nor do they suffer the same negative consequences if transmission service levels are poor*.[1]

A6. Finally Hydro One and their surveying agent, Innovative Research Group, imply that the transmission business is too complicated for the average consumer to understand. However we have witnessed a large of Innovative Research surveys commissioned by LDCs explaining the intricacies of local distribution systems. From our perspective explaining to end-use customers the intricacies of a local distribution system is much more challenging than explaining the relatively uncomplicated exercise of moving high voltage power from points A to B.

A7. In our submission the lack of meaningful input from the large body of Ontario ratepayers as to the trade-offs inherent in this costly Transmission System Plan (TSP) and the outcomes it promises to delivery is a significant weakness in the Applicant's proposal. So is the lack of a comprehensive report of LDC issues and how they are addressed.

A8. We also find that given the reliance on LDC representatives to provide feedback the absence of any questions asked with respect to Customer Delivery Point Performance Standards (CDPPS) is perplexing. As noted in our examination of Hydro One CDPPS have a direct financial impact on LDCs. The standards are also part of the existing and proposed Scorecard of Hydro One TX. As we have noted now in a number of transmission proceedings the data for the standards are closing in on 3 decades in age. Furthermore the premise of different standards for different load delivery points has not been revisited since the establishment of the CDPPS around 20 years ago. In essence the variation in standard by delivery point load

[1] Decision and Order EB-2016-0160, September 27, 2017, page 37.

capacity penalizes small delivery points like those of rural and isolated LDCs or First Nation Communities. Notwithstanding this and the fact that CDPPS are on the proposed scorecard no direct engagement was had as to the relevance of the existing standards.

A9. Hydro One has a very limited number of customers – about 156- composed of 63 LDCs, 84 directly connected customers and approximately 9 generators[2]. It has only recently implemented a program of account managers for each of these customers. It would seem to us the most effective customer engagement would be to have account managers assigned for each of its customers and use their insight as an input for the utility planning. In our cross-examination of the issue we tried to demonstrate the value of this information in determining whether investments are meeting the needs of its customers – especially LDCs. In setting the revenue requirement for Hydro One transmission the Board should be in the position of knowing if any of the 63 local distribution companies, which it also regulates, have outstanding issues with the transmitter and whether its capital and maintenance programs are adequately addressing these concerns. This is not the case with the current Application.

A10. In our view Hydro One has managed to present the worst of both worlds. It could, but has not, presented a clear and precise list of the concerns of each of its 156 customers. Specifically it does not have a comprehensive list of the issue LDCs have with its service. At the same time it does not understand how the end use customers (those behind the 63 LDCs) view its ambitious capital program. Surveys such as those undertaken by Innovative Research, are best suited to discovering the latter. A more comprehensive reporting by account managers might address the former.

[2] Vol. 7, October 31, 2019, page 62

Bill Impacts

A11. Bill Impacts for a typical residential customer are shown below.[3] The impacts are not large and could be reduced if the Board accepts our recommendations. In any event, in our view no mitigation is required.

Table 7: Typical Medium Density (R1) Residential Customer Bill Impacts Revised from Exhibit I2, Tab 5, Schedule 1 – Table 3

	Typical R1 Residential Customer					
	Blue Page	**CoC Update**	**Blue Page**	**CoC Update**	**Blue Page**	**CoC Update**
	400 kWh	**400 kWh**	**750 kWh**	**750 kWh**	**1,800 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$83.40	$121.75	$121.75	$236.81	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$4.78	$8.96	$8.96	$21.50	$21.50
Estimated 2019 Monthly RTSR[2]	$5.10	$5.10	$9.56	$9.56	$22.95	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.13**	**$0.24**	**$0.24**	**$0.58**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR[3]	$5.52	$5.30	$10.35	$9.93	$24.83	$23.83
2020 increase in Monthly Bill	**$0.42**	**$0.20**	**$0.79**	**$0.37**	**$1.89**	**$0.89**
2020 increase as a % of total bill	*0.5%*	*0.2%*	*0.6%*	*0.3%*	*0.8%*	*0.4%*
Estimated 2021 Monthly RTSR[3]	$5.84	$5.58	$10.96	$10.47	$26.29	$25.13
2021 increase in Monthly Bill	**$0.32**	**$0.29**	**$0.61**	**$0.54**	**$1.46**	**$1.30**
2021 increase as a % of total bill	*0.4%*	*0.3%*	*0.5%*	*0.4%*	*0.6%*	*0.5%*
Estimated 2022 Monthly RTSR[3]	$6.17	$5.93	$11.56	$11.12	$27.76	$26.68
2022 increase in Monthly Bill	**$0.32**	**$0.34**	**$0.61**	**$0.64**	**$1.46**	**$1.54**
2022 increase as a % of total bill	*0.4%*	*0.4%*	*0.5%*	*0.5%*	*0.6%*	*0.6%*

Effective Date

A12. Hydro One filed the Application in March of 2019. The timeframe is similar to that required by the Board for LDCs seeking an implementation date of January of the following year. Hydro One has acted responsibly, met the timelines established by the Board and made best efforts to complete the process in a timely fashion. For these reasons it is our submission that the effective date of final rates be January 1, 2020.

A13. Since the Board has established interim rates we do not see the need for the establishment of a Foregone Revenue Deferral Account. In our view it is simpler for the Board to order the recovery of any deferred amounts through the establishment of the appropriate rate rider.

[3] Undertaking J8.5

B: Custom Application

Are all elements of Hydro One's proposed Custom Incentive Rate framework for the determination of revenue requirement appropriate?

Formula

B1. The revenue cap formula proposed is essentially the same as that applied for, and approved by, the Board for the Hydro One's affiliate Hydro One Sault Ste. Marie LP (H1 SSM)[4].

RCI = I – X + C

Where:
- "I" is the Inflation Factor, based on a custom weighted two-factor input price index;
- 'X' is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Custom Productivity Stretch Factor; and
- "C" is Hydro One's Custom Capital Factor, calculated to recover the incremental revenue in each test year associated with its TSP.

The notable exception to the H1 SSM formula is the inclusion of a custom capital factor.

Inflation factor

B2. The inflation rate is the same 2-factor IPI proposed by H1 SSM and uses the same 14% labour and 86% non-labour weights. The rationale for this split is the same as provided in EB-2018-0218. The Board approved that inflation factor proposal and we see no compelling reason for it not to do this in this proceeding. The principle and argument are the same in both cases. The updated calculation for inflation of 1.8% as shown in the revised Table 3: Derivation of Inflation Factor at Exhibit J8.5 is in the most recent estimate for this inflator.[5]

Productivity Factor

B3. Similar to the H1 SSM, Hydro One TX is seeking to have no base productivity factor applied. Similarly the Utility proposes no stretch factor to its formula. Both the evidence of Hydro One's consultant, PSE and Board Staff's consultant PEG, came to the same conclusions with respect to the productivity factors - a 0% adjustment. PEG and PSE differ on the detail of the calculations and on the concept as to whether a negative base productivity factor implies an inherent stretch factor. PSE argues it does not while PEG takes the contrary position.

B4. The evidence of both PSE and PEG with respect to productivity factors is essentially an updated version of what the Board has already considered in the H1 SSM proceeding. The

[4] Decision and Order, EB-2018-0218, Hydro One Sault Ste. Marie LP, June 20, 2019
[5] Board Staff Argument, December 11, 2019, page 17

range in base TFPs are as between -1.71% and -0.25% depending on which application or consultant is being relied upon. Basically both consultants have a 10 basis point variance around their respective results.

B5. None of this is evidence is very convincing. On this matter we reiterate our submissions in H1 SSM EB-2018-0218. The Board should carefully weigh the evidence provided by both PSE and PEG. All such studies inherently suffer from statistical variation due to data issues including data collection error, classification errors as well as debates on the appropriate data period. In all cases the data is from U.S. utilities where it is taken more as a matter of faith than fact that there is comparability with Hydro One. This is demonstrated by the simple fact that while both consultants adopt the same methodology their application and data choices can lead to results with over a 100 basis point difference. We do not think the methodology employed by either consultant is particularly robust nor worth the time and money to argue as to the minutia between them. It seems quite startling to think the Board would rely on either result given the wide variation that can result depending on how one applies essentially the same econometric model. In our submission, the Board might take note of the results in a general sense – that is that there is no evidence of productivity growth in the transmission business. However the spurious specificity of either of the consultant's results should be recognized. In our submission the Board should substitute its expert judgement in order to find incentives which improve outcomes rather than accept the status quo.

B6. We are also sceptical of the value of these exercises as they remind us of past similar debates before the Board with dueling cost of capital experts. Here at least the models (e.g. comparable earnings, equity risk premium, capital asset pricing, etc.) are widely accepted and studied by the larger academic community. In contrast industry specific TFP studies are relegated to a small group of non-academic consultants with a financial interest in the propagation of their techniques. The entomology of this expertise is almost exclusively, if not entirely, out of the University of Wisconsin. All practitioners rely on essentially the same model, same data and same statistical methods.[6] The Board has come to rely upon this small network of American consultants to help it make decisions that affect millions of Ontario ratepayers and especially impact low income consumers. We believe insight might be had in having the entire exercise reviewed by expert economists and statisticians unassociated with the parties, their models or their methodologies. A fresh eye and critical assessment of the veracity and value of these industry specific TFP studies could then be made. In any event the exercise has boiled down to one, which even if true, postulates that because a group of similar companies has a record of poor productivity then the Board should accept Hydro One should also. With respect this is hardly an exercise in incentive regulation rather it is a perpetuation of the status quo.

B7. Nonetheless we do agree with PEG's proposal for a 0.30% stretch factor. In our submission without such an adjustment and if the custom capital factor is approved, the formula bakes in an annual increase above the rate of inflation. The 0.30% is a modest adjustment which

[6] For example see the testimony of Dr. Jeff Makholm in Enbridge-Union Amalgamation EB-2017-0306/307 Volume 4, May 15, 2018 explaining the genesis of the TFP work.

recognizes the general results of both consultants that the industry is not highly productive but needs to be incented to become so. The Board ordered a 0.3% adjustment in the Hydro One SSM proceeding and there is simply no reason why it should not apply the larger affiliate utility.

C-Factor

B8. One difference as between the proposal in this application and that in the Hydro One SSM proceeding is the inclusion of a C-factor. The C-factor has been utilized by Toronto Hydro in a number of rate plans and it's closely related to the "M-Factor" proposed by Alectra in its recent proceeding EB-2019-0018. The premise of these adjustments is to increase the revenue requirement to reflect "unfunded" rate base growth during the term of the plan.

B9. PEG has in this proceeding, as in past where similar proposals have been made, pointed to the lack of incentives in the "bare bones" application of the C-Factor. It then calculates an "S-Factor" in order to equate the C-Factor with the incentive mechanism arising from the threshold values used for the alternative to the C-Factor - ACM (or ICM) funding. PEG adjustments have been equated with the ICM/ACM framework and to work to find the equivalent threshold value. PEG suggests the equivalent value is 0.31%.

B10. We agree with the suggestion of PEG that, if utilized, "capital factors" require an incentive component. What we are less clear on the premise that such an "S-factor" is informed, in the opposite direction of the X-factor. It seems to us these two adjustments serve completely different purposes. The X-factor provides an incentive to the entire revenue requirement. The S-factor, at least as proposed by PEG, simply modifies the C-factor to be as if the incremental capital sought was under the ACM/ICM policy provisions. By way of example Hydro One SSM's approved revenue requirement formula has no C-Factor. If it were to file an ICM (which Hydro One SSM proposed be available to it the expectation would be that it meet the threshold criteria of the ACM/ICM policy. In this scenario we would not expect to see a proposal to reduce the 0.3% stretch factor currently in the approved H1 SSM rate plan. That is the two concepts are entirely separate and serve entirely different purposes.

B11. In order to prevent gaming as between regulatory vehicles to fund capital programs the Board should ensure equivalency in its policies. As such we believe the entire 0.31% S-Factor should be applied to the formula.

B12. VECC has considered the arguments of Board Staff with the respect to the application of inflation to the C-Factor. While conceptually correct we would note that the variance implied is likely to be minimal and in any event the C-Factor does not imply a level of precision that makes the inclusion or exclusion of inflation adjustment meaningful. Hydro One's proposed approach is consistent with its distribution plan and therefore, at least in respect to issue of inflation adjustment, we believe can be reasonably approved as applied for with, as we argue an S-factor applied.

Growth Factor

B13. VECC accepts that the given the short term of the rate plan and the absence of any evidence of significant growth in the transmission business no growth factor is warranted.

C: Productivity Improvement and Performance Scorecard

Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations?

Are the metrics in the proposed scorecard appropriate and do they adequately reflect appropriate outcomes? Do the outcomes adequately reflect customer expectations?

What is the status of Hydro One's joint work with the IESO to explore cost effective transmission line loss reduction opportunities and to report on those initiatives?

Productivity Initiatives

C1. Hydro One has responded to the Board's past decision by identifying both embedded and non-embedded productivity savings in this Application totalling $704M. This amount is broken down into three categories: $353M in capital productivity savings, $114M in OM&A productivity savings and $237M in undefined capital savings under the ambit of what is called "progressive productivity". Progressive productivity savings, somewhat confusingly, include both defined initiatives ($49M) and undefined initiatives ($237). In any event all $704M is baked into the cost forecast over the term of the rate plan under the ambit of "Tier 1 "productivity initiatives.

C2. A second concept "Tier 2" productivity benefits is explained in the following way:[7]

> *If Finance approved the initiative and confirmed that it would have the effect of reducing a department or program budget, then the initiative was deemed to qualify for tracking and reporting against the company's Tier 1 Productivity target up to the forecast amount of the spending reduction, with further savings to be tracked as Tier 2 Productivity savings.*

C3. The sum total of forecast productivity savings by year and by category are shown in the table below:[8]

[7] Exhibit B-1-1, TSP Section 1.6, page 4 of 13.
[8] Undertaking JT2.28, Attachment 1

JT-2.28	2016	2017	2018	2019	2020	2021	2022	2023	2024	20-24 Total
Total Capital	1.20	18.00	39.40	43.60	61.70	88.70	112.20	129.20	143.40	**535.20**
Total OM&A	3.80	8.00	14.80	14.70	14.70	18.60	17.90	18.30	17.80	**87.30**
Total Common	2.30	3.10	6.80	22.40	21.50	18.80	16.00	13.60	11.70	**81.60**
Attach 1	**7.30**	**29.10**	**61.00**	**80.70**	**97.90**	**126.10**	**146.10**	**161.10**	**172.90**	**704.10**

C4. We make two observations from this data. The first is that the predominate share of productivity savings come from the capital investment category which accelerate in the latter years of the rate plan. The difficulty (as also explained in Board Staff's argument) is in trying to establish a baseline for capital projects which, especially in the latter years are still largely undefined in terms of scope and cost. The unintended consequence being that Hydro One might be inclined to more liberally forecast the costs of capital projects the farther in the future and hence more uncertain they become. At a macro level there is no robust way to disentangle true productivity savings from projects which are completed for less than an unrealistic (or at least unchallenging) original cost estimate.

C5. The other notable point is that the initiative pre-date the rate plan years. As of the end of 2018 Hydro One estimates it has achieved $97.4 million in savings. For the OM&A category this begs the question as to when a productivity initiative becomes simply "business as usual".

C6. Tasking the Utility to demonstrate future productivity initiatives as part of a regulatory application is inevitably a difficult undertaking. It is clear that given the expansive capital budget proposed the productivity of Hydro One transmission – as measured by costs over a fixed number of units of energy transmitted - will continue to decline over the course of this rate plan. This is in fact consistent with the evidence of both PEG and PSE who point to expansive capital budgets as the reason for productivity decline in the industry as a whole. What Hydro One is attempting to show is that it will decline less than if it wasn't engaging in productivity initiatives. Of course with respect to capital spending part of the question is not whether capital programs are being delivered as effectively as possible, but also as to whether they are needed in the first instance. Or at least in the rate plan time frame. We would suggest that ratepayers are rather indifferent to the savings made (or purported to be made) on something they don't really need.

C7. To be fair, Hydro One has tried to address the capital productivity issue as articulated by the Board in its last Decision. As we understand it there is a business process in which the Finance group are charged with ensuring there is a measurable benefit. In this way at least we believe Hydro One has addressed the Board's comments in that Decision. The evidence of the success of this initiative, we believe, will be demonstrated (or not) in the reporting the Utility provides as part of its next cost of service application. In our submission the Board might emphasize the need to demonstrate the productivity savings and might itself consider whether third party audits of a sample of these initiatives should be carried out.

Scorecard

C8. With respect to the Performance Scorecard we make three observations. The first is the reliance on the SAIFI for outage metrics. While there is nothing inherently wrong with this metric it is strongly correlated with weather making interpreting the results difficult. To address this issue we believe the Scorecard should report outages, both frequency and duration, due to defective equipment. Hydro does this metric (at a sub level) but does not report it on the scorecard. Outages due to equipment failure are, we would argue, a much better indicator of efficacy of a capital program than SAIFI.

C9. Our second observation is with respect Customer Delivery Point Performance Standards (CDPPS). In our submission the standards in question should be reviewed and at a minimum updated to reflect the most current data rather than the 20 year and older data it now includes. We believe the Board might also revisit the premise that low volume delivery points should have a lower standard than larger delivery points. The current standard we believe discriminates against small isolated LDCs and indigenous communities.

C10. Finally, and most importantly, we continue to advocate for a relationship between the scorecard outcomes and the rate plan (in this case revenue requirement) formula. In our submissions those metrics related to reliability (System Unavailability, Unsupplied energy, SAID/SAIFI, CDDPS) could be connected to amount a utility is able to recover in subsequent years. For example, should the Board be inclined to grant the entirety of Hydro One's ambitious capital program and to only so see system unavailability to increase one might question why the Utility would be rewarded with an increase in revenues. In such circumstances it seems to us the entire premise of the RRWF "outcomes" focused regulation relies on a link between outcomes and the rates (revenues) a utility is allowed.

D: Transmission System Plan

Are the proposed forecast capital expenditures and in-service additions arising from the transmission system plan appropriate, and is the rationale for planning and pacing choices (including consideration of customer preferences, planning criteria, system reliability, asset condition and benchmarking appropriate and adequately explained?

Are the methodologies used to allocate Common Corporate capital expenditures to the transmission business and to determine the transmission Overhead Capitalization Rate appropriate?

Is the proposed capitalization of other post-employment benefits (OPEB) for both Hydro One Transmission and Hydro One Distribution appropriate, and if not, what is the appropriate approach for these costs?

Does Hydro One's Transmission System Plan sufficiently address the unique rights and concerns of Indigenous customers and rights-holders?

D1. The Transmission System Plan (TSP) was developed under an elaborate eight step process described by Hydro One. Fundamentally though, like all such plans, the matter ultimately boils down to a two-step process. Step 1 is to determine the condition of the asset population. Hydro One performs a continuous asset risk assessment ("ARA") process to determine individual asset needs. The ARA is primarily concerned with the major equipment groups (e.g. transformers, conductors, breakers, and protection and control systems) that directly affect system.

D2. The ARA comingles step two, which uses asset condition as an input to an broader analytical framework (like the CopperLeaf 55 software system) which considers other aspects of the delivery service, like the probability of failure, safety, criticality of the asset and exogenous requirements like those arising from the regional planning process in order to determine an order of investment needs.

D3. Hydro One explains that as part of the ARA process, transmission assets are evaluated on the following six risk factors:

- Condition
- Demographics
- Criticality
- Performance
- Utilization
- Economics.

D4. The output of the asset condition assessment are shown below and Hydro One describes the results in this fashion:[9] "

[9] Exhibit B, TSP Section 2.2, page 3 of 117

The risk rating of individual assets is based on the probability of failure determined through qualitative and quantitative assessment. Quantitative assessment considers the results of diagnostic testing as well as the corrective history of the asset which may indicate a higher probability of failure. Qualitative assessment is based on engineering analysis and judgment to assign a relative risk level.

Table 1 - Major Asset Condition Summary

Asset Type	Very Low Risk*	Low Risk	Fair Risk	High Risk	Very High Risk*	To be Assessed
Transformers	336	163	95	99	23	-
Circuit Breakers	2035	1475	804	293	167	-
Protection Systems	4,800	3,846	497	2,387	976	-
Conductors (km)	16,050		3,316	3,680		6,061
Wood Poles	-	17,640	0	5,460	-	18,900
Underground Cables (km)	-	179	77	8	-	0

** These categories are not used for all assets.*

D5. Two other concepts are used in the TSP – Expected Service Life (ESL) and End of Life (EOL). Hydro One defines these as[10]:

- ESL is defined 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's historical asset retirement data. Assets operating beyond ESL generally have a higher likelihood of failing or being in poor condition.

- EOL is defined as the likelihood of failure, or loss of an asset's ability to provide the intended functionality, wherein the failure or loss of functionality would cause unacceptable consequences. Therefore, while assets may be operating beyond ESL they may not be at EOL. At the same time, as the primary driver of replacement decisions, asset condition will be verified prior to the work being undertaken.

  (emphasis added)

D6. The concept of ESL is used throughout the evidence as a means of demonstrating the urgency to address an asset class. As is shown, for example, by the chart below which

[10] Exhibit B, TSP Section 2.2, page 1

attempts to show how Hydro One it will be addressing an increasing population of ESL transformers.[11]

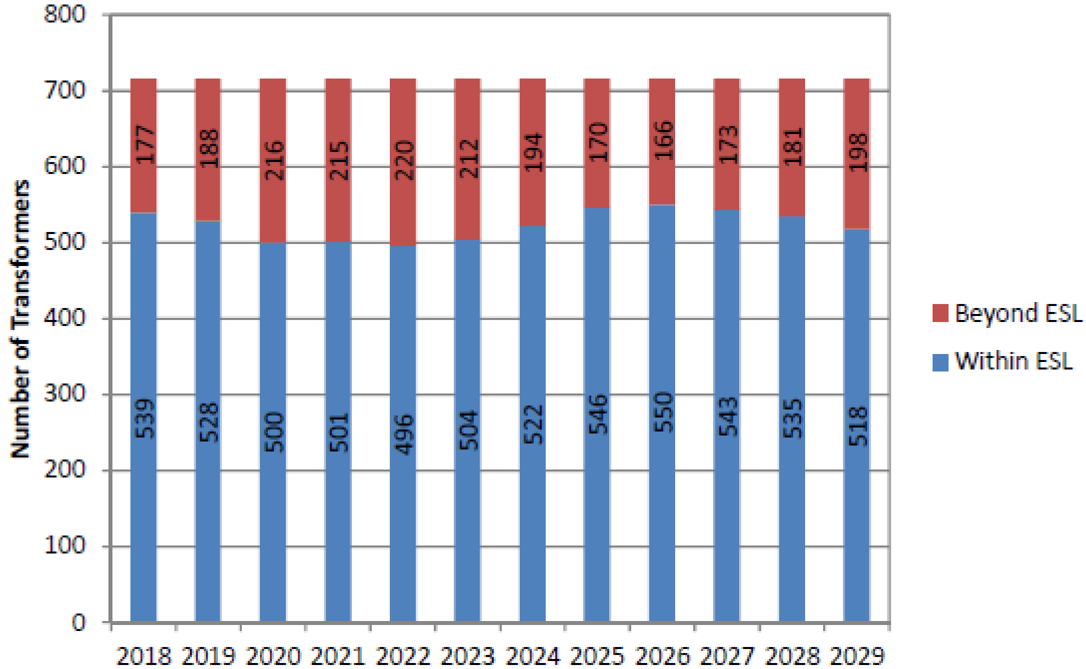


Figure 7 – Transformer Demographic Forecast – With Replacement

D7. The difficulty in assessing Hydro One's TSP is that it combines the issue of asset condition – that is whether the asset is in good, fair or poor condition, with the concepts of the failure risk and criticality of the asset. All of these are important to consider but in each step there also is introduced a certain amount of subjectivity. Hydro One itself acknowledges the inevitable need for some subjectivity in the exercise stating "*although asset analytics aids in the identification of asset 9 needs as an initial step, it is not the sole input or driver of the ARA. Hydro One planners take into account a range of other considerations and data sources, as informed by sound engineering oversight and experience-based decision making, in the initial determination of asset needs, which are then ultimately verified against asset condition assessments*[12]."

D8. The concept of ESL or end of service life can be highly subjective. For some equipment it may be based on no more than the manufactures warranties and, likely conservative, estimate of how long the asset it produced will provide reliable results. Some other assets, like fleet vehicles have no "stamped" ESL. For these Hydro One simply uses its assessment of the years and mileage for which it will use a vehicle before it determines it is no longer worth maintaining.

[11] Exhibit B, TSP Section 2.2, page 14 of 117
[12] Exhibit B-1-1-, TSP Section 2.1 page 15

D9. An interesting example of the issue of what meaning exists in ESL is demonstrated by wood poles. Below is a table showing the investment need for this category of assets and as described by Hydro One[13].

Table 1 - Wood Pole Structure Demographics

Wood Structure	Quantity	Average Age	ESL (Years)	Beyond ESL currently	Beyond ESL 2024	Beyond ESL 2029
Total	42,000	41	50	14,400	15,100	17,940

Wood structures deteriorate over time. The rate of deterioration depends on many factors including location, weather, type of wood, treatment, insects and wildlife. As a result, uniform deterioration does not occur and the condition of wood structures varies, even in the same location. Due to the nature of the design, the wood cross-arm tends to be the weak link and is typically the primary cause of failure.

D10. Here we see that determining the service life of a class of assets can be very complicated. First is the question of how the asset is assessed – are they all assessed the same manner? Do some poles have physical testing, while others only visual inspection. Is every pole tested or just a sample? Depending on the type of asset condition might be determined by stringent physical testing of all assets in that population, for example, transformers asset condition are determined by periodic dissolved gas testing. For other assets like wood poles parts of the population may be tested and a condition for the asset class extrapolated from that sample. The asset condition might also be less rigorous sometime being no more than a visual inspection.

D11. While we believe Hydro One's TSP to be a rigorous exercise it would benefit, in our view, from clarity as to the evidence on asset condition and the application of the subsequent analytics which convert that asset condition into an investment need. For example, we think information showing simply the asset condition in terms of good, poor etc., and the means by which that assessment is made (e.g. Physical testing, sampling of population etc.) provides a clearer initial start to any asset investment plan. It also allows for a baseline under which in subsequent proceedings the utility can be measured as to the improvement of the condition of its assets.

D12. For the purpose of determining what amount of investment should be included in the current rate plan our argument is simply that TSP incorporates a considerable amount of judgement and estimation. To be fair, all such exercises must since there is no linear path to be had in making the calculation as between risk of asset failure, its consequence and the cost of preventative investments. We do not intend to repeat the detailed argument of Board Staff on this issue. In our view they make persuasive arguments at the detailed level of the TSP.

[13] Exhibit B, ISD SR-21, page 2 of 10

Rather we invite the Board to also consider a macro view of the TSP recognizing that there is a certain level of subjectivity and conservativeness in Hydro One's plans. By conservative we mean that the Utility is more inclined to invest in new assets than risk failure inherent in maintaining older assets. This is simply because as a monopoly there is more downside risk to service interruption than revenue interruption for which there is no risk.

D13. Below, using three charts, we compare Hydro One transmission's current proposed capital planning with that put forward in the prior application EB-2016-0160. The bridge year in the prior application is 2016 and the test years were 2017 and 2018 in EB-2016-0160. The proposed capital program, showing a significant increase in costs is shown in the table below[14]:

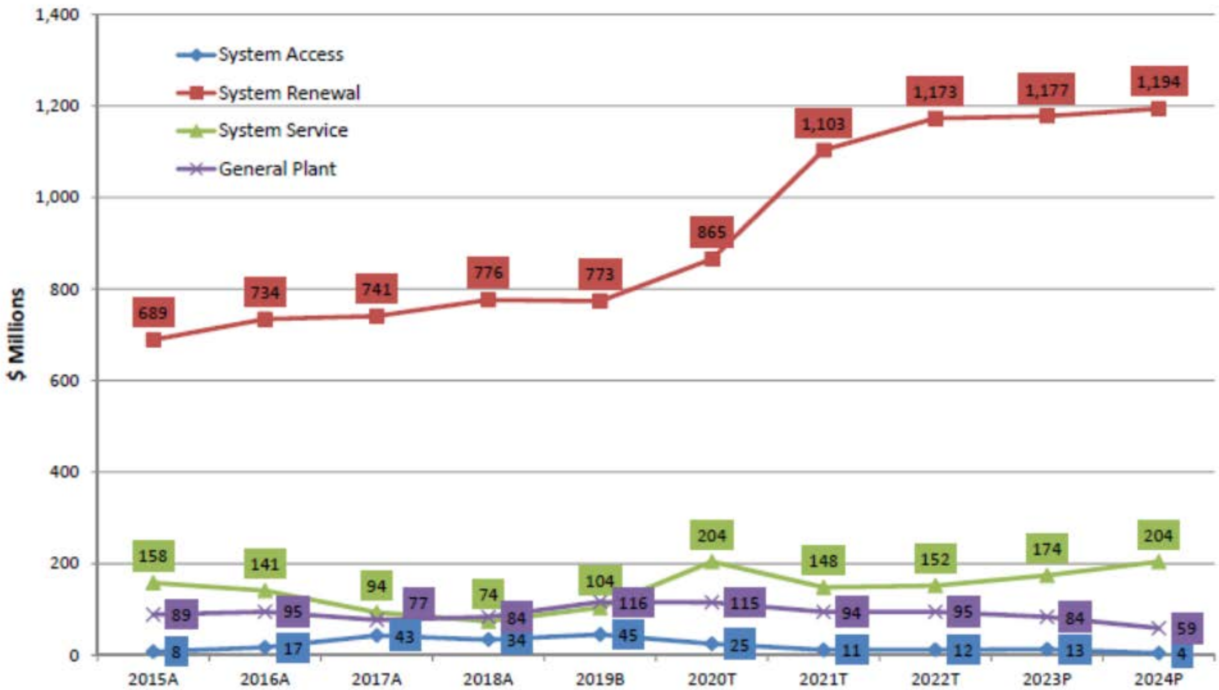


Figure 1 - Actual / Forecast Capital Expenditures 2015 - 2024 by Category
(A=Actual, B=Bridge Forecast, T=Test Forecast, P=Plan)

D14. Below Table 4-1, which shows what was proposed to the Board in EB-2016-0160 is compared to the spending shown in updated Appendix 2-AB:[15]

[14] Exhibit B-1-1, TSP Section 3.1, page 3 of 24.
[15] HONI_Updated Ex_B-01-03_20190619_Cap Ex Summary Tables – excludes Directive and pension adjustments and Decision and Order, EB-2016-0160, September 28, 2017, page 25

Table 4-1
Transmission Capital Expenditures, 2012 – 2021
$ million

Investment Category	4 year Historical Actual Expenditures				Bridge Year	Test Year 1	Test Year 2	Forecast Expenditures		
	2012	2013	2014	2015	2016	2017	2018	2019	2021*	2022*
Sustaining	$ 389.3	$ 480.0	$ 621.3	$ 694.3	$ 724.3	$ 776.8	$ 842.1	$ 825.7	$ 915.2	$ 1,118.1
Development	$ 329.4	$ 171.7	$ 131.6	$ 166.0	$ 166.0	$ 196.4	$ 170.2	$ 244.0	$ 254.0	$ 258.3
Operations	$ 15.2	$ 17.7	$ 28.4	$ 15.6	$ 30.1	$ 25.4	$ 30.8	$ 58.8	$ 21.1	$ 24.7
Common Corporate Costs	$ 42.1	$ 49.1	$ 63.4	$ 67.1	$ 83.5	$ 77.6	$ 79.1	$ 79.1	$ 78.2	$ 73.8
Total	**$ 776.0**	**$ 718.5**	**$ 844.7**	**$ 943.0**	**$1,003.9**	**$1,076.2**	**$1,122.2**	**$1,207.6**	**$1,268.5**	**$ 1,474.9**

Source: Exhibit B1/Tab3/Schedule 1/p.1

* NB Years 2021 and 2022 are mislabelled and should read 2020 and 2021.

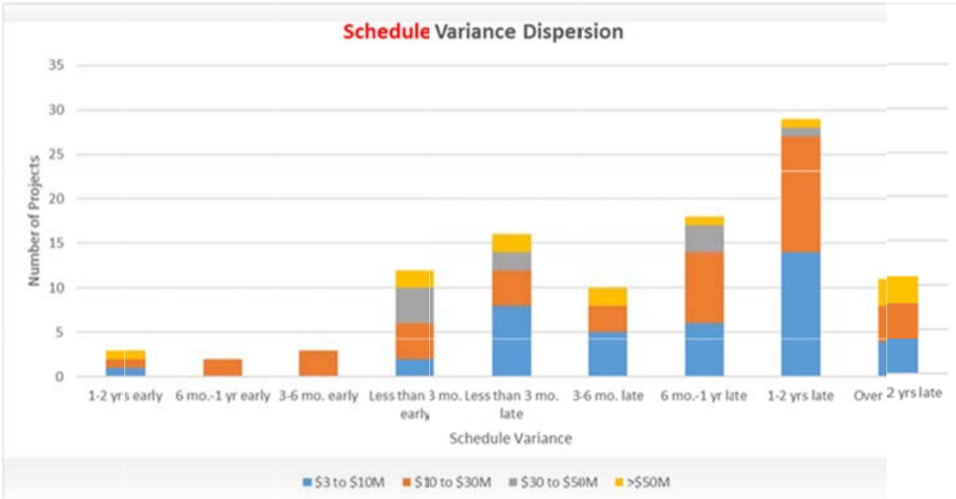
CATEGORY	**Historical Period** (previous plan[1] & actual)									**Forecast Period** (planned)				
	2015		2016		2017		2018		2019	2020	2021	2022	2023	2024
	Plan	Actual	Plan	Actual	Plan	Actual	Plan	Actual	Actual[2]					
System Access	19.7	7.6	31.9	17.0	33.3	42.7	24.3	33.7	45.1	24.8	11.3	11.7	12.7	4.1
System Renewal	573.6	688.9	539.9	733.9	733.7	740.7	780.4	776.2	773.3	865.2	1,103.1	1,172.8	1,177.4	1,193.8
System Service	189.9	157.9	180.0	140.9	97.0	93.5	75.6	73.9	103.8	204.1	148.2	151.8	174.3	204.2
General Plant	116.3	88.6	114.6	94.8	86.0	76.9	119.7	83.6	116.3	115.4	94.4	94.7	83.6	58.9
Progressive Productivity Placeholder										- 17.0	- 39.0	- 61.0	- 78.0	- 91.0
TOTAL EXPENDITURE	**899.4**	**943.0**	**866.3**	**986.7**	**950.0**	**953.9**	**1,000.0**	**967.3**	**1,038.5**	**1,192.5**	**1,318.0**	**1,370.0**	**1,370.0**	**1,370.0**

D15. It is interesting to observe that while the Board reduced the 2017 capital investment (for the purpose of rates) by $126.1 million and the 2018 investment proposal by $122.2 million the Utility still managed to underspend the allotted amounts. We have to wonder that if matters have now so deteriorated so much as to urgently need a massive increase in capital spending why the past period is characterized by underspending on a reduced capital budget. If the facts are as being purported in this application one might have expected the opposite to have occurred.

D16. There is a clear pattern of the Utility having a surge in capital investment in the bridge year of its applications along with proposals to make large increase from that level in the test years. In our submission the way to address this type of behaviour is to set the capital spending at a level commensurate with the average of the years prior to the bridge year. In this case if we take the years 2015 through 2018 we find an average spending level of $962.55M. This figure is similar to the actual spending in 2018 the year before the bridge year in this application. In our submission the Board should consider this figure as the starting point and then adjust for inflation and any special needs arising from the TSP that it finds persuasive. For example, Hydro One has made the case for a larger program for conductor replacement. We suggest that the resulting figure would be somewhere between the 2019 forecast spending of $1,039M and the proposed 2020 spending of $1,193(rounded). An annual increase slightly above the expected inflation rate of between 5-10%). The resulting reductions would in our view average about $100 million per year from the proposal of Hydro One. We acknowledge that this is not a precise figure, but in our view there is no "correct" number only a reasonable amount to be included in the revenue requirement. In our submission the capital investment to be embedded in the revenue requirement must have consistency with past spending as the TSP in no way offers an explanation for the abrupt change in spending patterns.

<u>Impact of lower capital investment</u>

D17. In making any adjustment to the proposed capital spending plan the Board might also consider the evidence as to the reliability risk any reduction might entail. Partly, the response to this is that there is a significant amount of spending on items, especially in the category of general plant that do not directly impact safety. If required Hydro One always has the ability to manoeuvre by delaying lower priority project to address pressing needs. In fact as shown in the graph below showing the variance in scheduling of projects Hydro One often does significantly adjusts its planned capital budgets to meet changing priorities.



D18. Moreover, the evidence does not paint any picture of imminent catastrophe. One can see that by examining past reliability outcomes and as shown in the graph below which shows frequency of outages by category of failure.[16]

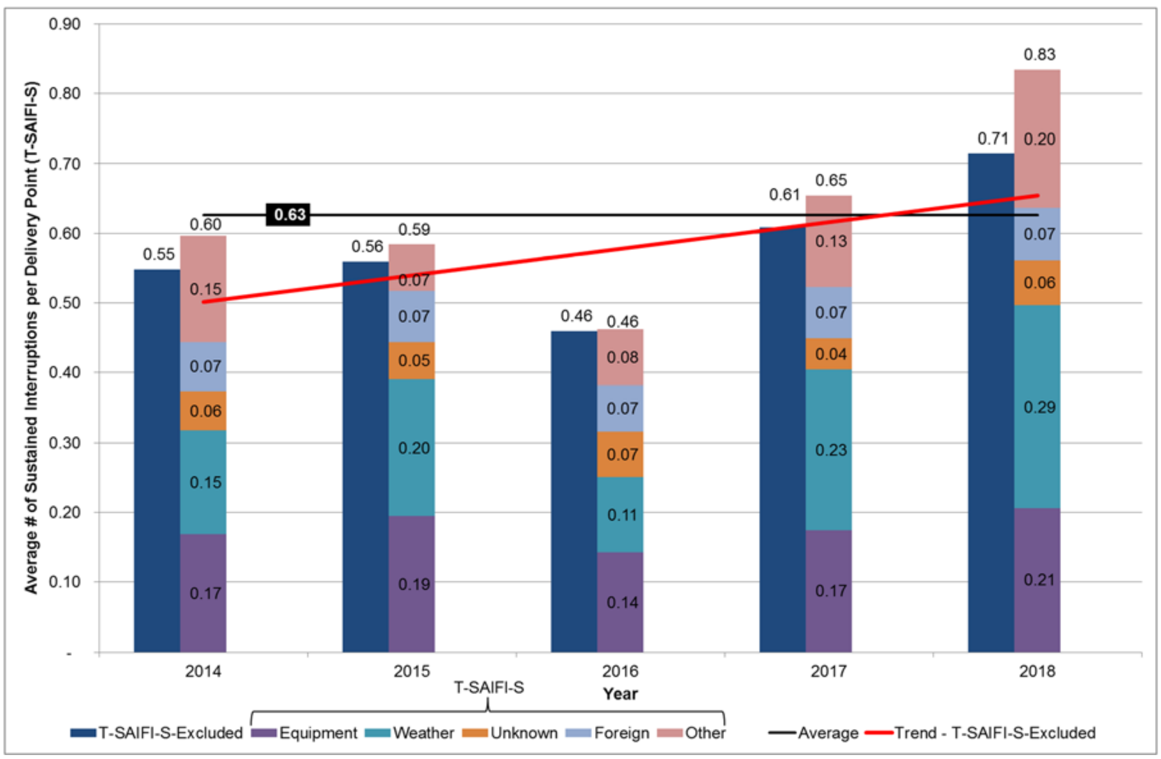


Figure 6 - Transmission System Average Interruption Frequency Index – Sustained Interruption

[16] Exhibit B-1-1, TSP Section 1.5, page 29 of 55

D19. On first glance the chart appears show declining reliability outcomes. However, if one removes the interruptions caused by weather the picture is much different. Interruptions due to equipment failure only increase slightly in 2018 and appear to fluctuate around a point (0.17) over the period.

D20. Outages due to equipment failure can be further broken down into the category of equipment as shown in the table below.[17] Again, while there is some negative change, as with Line caused outages, there is no dramatic trend suggesting a break with past experience.

	2014	**2015**	**2016**	**2017**	**2018**	**5-Year Total Ave**
Line	23.1%	27.0%	41.5%	35.9%	44.7%	35.3%
Breaker	57.1%	47.3%	41.5%	45.7%	33.5%	44.1%
Transformer	16.4%	21.6%	13.5%	14.7%	18.4%	17.0%
Other	3.3%	4.0%	3.5%	3.6%	3.2%	3.6%
TOTAL	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

D21. In our submission there is no overwhelming evidence which suggests a reduction of 100 million per year in the annual capital investment budget would result in a significant deterioration of system reliability. In any event this reduction would be less than that ordered by the Board in its last Decision and with little apparent consequence to reliability.

Integrated System Operating Centre - Orillia

D22. As anticipated from its distribution application EB-2017-0049 Hydro One is seeking to recover the transmission allocated amounts for the proposed new operating centre. The current Class 2 level estimate (-4% - +6%) is $154.5M as shown below. This is $16.1 million more than the request presented in EB-2017-0049. The distribution and transmission allocations are 50.07% and 49.93% respectively.

D23. In its March 7, 2019 EB-2017-0049 Hydro One Distribution Decision the Board directed the Utility to establish an asymmetric variance account to track the actual cost of the distribution portion of the ISOC against the forecast total cost of $69.3 million in that application (i.e. 50.07% of $138.4M).

D24. There is a difference between the amount shown in the business case approved by the Board of directors and that being sought the application. The amount in the business case approved by the Board of Directors on August 1, 2019 is shown in the table below. The amount being sought in the application was $159.8 million. Hydro acknowledged the updated savings of $5.3

[17] Undertaking J3.6

and indicated it would update the transmission-allocated costs and hence the revenue requirement and in-service addition being sought for recovery in this application.

Category	Cost ($M)
Total Development Phase*	$11.2
Construction Phase:	
General Contractor Construction **	$91.9
Telecommunication and Dual Power	$9.7
Data Centre and other IT equipment	$9.1
Furnishing	$3.6
Project Management and Commissioning	$1.4
Contingency	$6.7
Decommissioning of BUCC	$0.5
Interest and Overhead	$20.4
Total Project Cost	$154.5

D25. In our submission the Board should establish the same type of asymmetric account for the transmission allocated portion of the control centre costs as it did in the distribution proceeding. However, we also hold that the amount to be recovered in rates should be based on an allocation of the original amount of l $138.4M. This maintains consistency with the original approval of the Board for this project.

D26. In our submission Hydro One should be required to establish an asymmetric variance account for the 49.93% transmission allocated portion of the control centre. The allocated portion of transmission is either 49.93% of the original amount or the new amount (.4993 * $154.5) is $77.14 million

E: Operations Maintenance & Administration Costs

Are the proposed 2020 OM&A expenditures appropriate and is the rationale for planning choices appropriate and adequately explained?

Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the transmission business appropriate?

Are the amounts proposed to be included in the revenue requirement for income taxes appropriate, including consideration of the Accelerated Investment Incentive (Federal Bill C-97)?

Is Hydro One's proposed depreciation expense appropriate?

E1. On the face of it Hydro One's proposed OM&A costs appear to be a good news story. Total Transmission OM&A appear to show a declining trend beginning in 2015. OM&A spending will be about $85M less in 2019 than in 2015. The difficulty is that OM&A figures as presented by

Hydro One present only a part of the story. A large component of OM&A is compensation costs. At approximately $176M compensation represent about half of all OM&A costs. Two critical factors can, and do confuse the presentation of that category of costs. The first is the total amount of compensation capitalized in any given year. As capital budgets increase so does the proportion of labour costs that find their way into the capital portion of cost recovery. For example, in 2015 $391M in compensation costs were capitalized – in 2019 the equivalent figure is about $466M.[18] To the extent FTEs are not temporary and hired specifically for the purpose of capital projects there is inherent liability that will be recovered in OM&A if not capitalized. Put another way – even if Hydro One's capital investment plan were to be reduced by a significant amount the result, we think, would be a related increase in the amount of OM&A costs.

E2. It appears that Hydro One has made some steps to recognize this issue by increasing the number of Temporary and Casual Employees, but the increase in flexibility gained by this strategy appear to be modest and are difficult to judge. VECC submits that Hydro One's compensation costs are inordinately high and that more should be done to control both the number of FTEs and compensation per FTE. We address that issue below.

E3. Other than the embedded compensation costs our only other issue with the OM&A proposal is that it would appear to not fully recognize the benefits of its large capital investment plan. Staff has made detailed argument with respect to the various components of the OM&A programs. We submit there is merit in their views.

E4. In order to address both issues we are in agreement with Board staff in that the 2019 year should be taken as a base year and that compensation should be increase for inflation from that year. Staff has suggested 2% and we believe this is a reasonable inflator. This approach we note would be very similar what has been in seen in a number of recent distribution utility rebasing applications.

F: Compensation Costs

Are the compensation related costs appropriate?

F1. Over the 2017 through 2022 period FTEs allocations to the Transmission function are increasing from 4,304 to 4,613. The total headcount for the Utility is expected to increase from 8,077 in 2015 to 9,266 in 2019 and drop modestly thereafter.

F2. The Mercer Compensation Benchmarking Study (summary shown below) shows that there is no significant improvement in Hydro One's compensation parity. On an overall weighted average basis, for the jobs Mercer reviewed in 2017, Hydro One is approximately 12% above the market 50th percentile.[19] Given the fact that the comparator group changes over time and

[18] Exhibit I, Tab 07, Schedule 58 (SEC-58 or Exhibit K6.2 SEC Compendium pages 41-)
[19] Exhibit F-4-1, Attachment 2, page

the study does not include some aspect of compensation like overtime it is hard to draw any strong conclusions from the 5% decline shown. The fact remains that total compensation for Hydro One is both higher than the market median and increasing above inflation.

Table 25: Mercer Compensation Benchmarking Study Results vs. Market Median Total Compensation Above/Below Market Median

Employee Group	2008 Survey Results	2011 Survey Results	2013 Survey Results	2016 Survey Results	2017 Survey Results	Total Change from 2008 to 2017
Management	-1%	-17%	-1%	2%	1%	2%
Society	5%	5%	9%	11%	12%	7%
PWU	21%	18%	12%	16%	12%	-9%
Overall	17%	13%	10%	14%	12%	-5%

F3. Even if the Board were to conclude some small progress has been made by Hydro One with respect to the comparator group this would not provide much comfort to the majority of ratepayers who have seen an increasing divergence between their incomes and those of the much smaller number wage earners working in government or quasi government organizations. The Mercer market sample reads as a “who’s who “of regulated utilities rendering the exercise entirely circular in nature. In the colloquial argument for these studies is the premise that Hydro One must pay Toronto Hydro level wages or lose employees in some notional competition for employees. Toronto Hydro then shows up before the Board with evidence to say the same about Hydro One. Each round notches up the wages of both. No evidence is offered to show a shortage of highly skilled competent people willing to work at the six figure level.

F4. In our view the Board should seek to understand better the gap between the compensation of the utilities it regulates and the customers who pay their bills. Hydro One certainly faces a difficult task in trying to reduce its compensation costs in a highly unionized environment. However, that challenge has been taken on outside the regulated environment and is shown by a stagnation of wages and demise of high cost benefits like the defined benefit pension plan. The better benefits given utility workers is all fine and good except that it fails to recognize a widening divergence between those workers and the wages of workers who pay for utility service. The result is that utility services take a larger bite out of the customer’s pocket. We believe that this is an issue that should be considered by the Board when it considers what a “reasonable” compensation amount is. For example, the Board might want to consider whether it will allow the total compensation bill to exceed the average wage increase in the province. If so it could consider requiring Hydro One in its next rebasing application to file evidence helping it understand the trend in Ontario wage rates. Such an exercise would at least provide the

Board and the Utility with a perspective on the compensation costs that is different than the usual Mercer type of circular study.

F5. For the purpose of this application our submission is that the Board recognize the continued above median compensation package by reducing the OM&A to an increase of 2% from the estimated 2019 level.

G: Rate Base & Cost of Capital

Are the amounts proposed for rate base (including the working capital allowance amounts) reasonable?

Is the proposed cost of capital (interest on debt, return on equity) and capital structure reasonable?

F1. VECC believes the updated values for cost of capital and the proposed application to the capital structure is reasonable and should be adopted by the Board.

F2. The only rate base adjustment to be made, we submit, is an adjustment for 2020 to reflect a lower capital investment program and therefore lower in-service amount of between $50 and y $100 million.

H: Load & Revenue Forecast

Is the load forecast methodology (including consideration of CDM impacts) and the resulting load forecast appropriate?

Are Other Revenue (including export revenue) forecasts appropriate?

<u>Load Forecast</u>

H1. Hydro One Networks' transmission load forecast is developed using three different energy models: two econometric models (one a monthly model and the second an annual model) and an end use model[20]. For CDM and embedded generation, the (pre-2018) energy impacts are added back to historical use values for modelling purposes. Based on these models forecast energy growth rates are developed and applied to the actual weather corrected demand for the base year (2017) to develop a forecast of Ontario demand, exclusive of the impact of future CDM and embedded generation[21]. A forecast of the impact of future CDM and embedded generation is then subtracted to arrive at the forecast used in the Application for the test years[22]. Weather correction is based on average weather conditions over the last 31 years[23].

[20] Exhibit E, Tab 3, Schedule 1, page 14 and Appendices A, B & C.
[21] Exhibit I, Tab 10, Schedule 26 (VECC 26)
[22] Oral Hearing, Transcript Volume 7, pages 94-95

H2. In principle VECC has no concerns about Hydro One Networks' approach to transmission load forecasting, i.e., i) the use of econometric and end-use models and ii) the incorporation of CDM impacts in the historical data used for forecast purposes and, then, iii) reducing the forecast by the anticipated impacts of CDM in the test years. However, VECC has a specific concern with the way this approach has been applied in the current Application.

H3. As noted above, Hydro One's energy models used in the forecast are based on historical data that has been adjusted so as to remove (i.e., add back) the CDM effects. For these purposes Hydro One has used the historic CDM values as provided in the IESO's 2016 Ontario Power Outlook (OPO)[24]. However, the 2016 and 2017 CDM savings values set out in the 2016 OPO are not really actual values but rather forecasted estimates[25]. When asked why the IESO's actual verified 2016 and 2017 verified results were not used Hydro One responded that the IESO report did not provide the necessary customer segment break down required[26]. In a subsequent undertaking response[27] Hydro One also noted that:

> "*this report[28] does not include historical (2006-2014) EE program and C&S savings. As such, it does not provide consistent historical results up to 2018 required for preparing forecasting models, and does not provide consistent bridge and test year data required for load forecast purposes.*"

H4. However, VECC notes that Hydro did have a file from the IESO that incorporated the actual verified results up to 2017 and that provided (on a consistent basis) the CDM savings for the period 2006-2017. Furthermore this file separated out EE programs from C&S savings and reported savings by customer segment [29]. VECC also notes that since CDM energy saving are only required to adjust the historical data used in developing the Hydro One's energy model consistent forecast data for the bridge and test years is not required.

H5. In its EB-2016-0160 Decision[30] the OEB agreed that the best information available at the time the load forecasts are prepared and filed should be used. It is VECC's submission that Hydro One has not used the best available information for purposes of preparing its current load forecast. The Board should insist that Hydro One do so in future Applications.

H6. In terms of the billing determinants used by Hydro One/IESO, during the review of Hydro One's 2017/18 Transmission Revenue Requirement (EB-2016-0160) CME raised a concern that when the monthly system peak falls outside of the 7 AM to 7 PM period, manufacturers who

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[23] Exhibit E, Tab 3, Schedule 1, page 11
[24] JT 2.34-Q3 c)
[25] VECC 22 a) ii)
[26] Oral Hearing, Transcript Volume 7, page 98
[27] J8.3
[28] Referring to the IESO's Report on Verified 2017 Provincial CDM results filed as J8.3
[29] This file is referenced in VECC 24 d) as item #7 and provide in JT2.34-Q2.
[30] Page 67

take steps to ensure that their manufacturing processes occur outside of the peak hours are nevertheless billed a higher network charge because their demand is coincident with the monthly system peak. In its subsequent Decision[31], the Board directed Hydro One to provide a report in its next transmission rates case that addressed how the Network Service Charge (NSC) determinant might be modified to respond to the concerns raised by CME.

H7. Hydro One filed such a report as part of its current Application[32]. The report evaluated an alternative that would limit the application of the Network Service Charge to the customer coincident peak demand within the peak period. However, the report also noted that based on data from 2012 to 2015 only two industrial customer delivery points were materially impacted by the NSC determinant. Furthermore, these two industrial customers appeared to have modified their behaviour in 2016 and 2017 such that going forward they are not likely to be negatively impacted when the system peak falls outside the 7 AM to 7 PM on-peak period. As a result, the report the recommended and Hydro One is proposing that the current NSC determinant definition be maintained.

H8. VECC supports Hydro One's proposal to maintain the current NSC definition. VECC agrees with the rationale put forward in the report prepared by Hydro One. However, VECC also notes that the fact the system peak sometimes occurs outside the "peak period" definition used for billing purposes raises a larger issue as to whether the peak period is appropriately defined which was not explored in the Hydro One study[33].

<u>Other Revenues</u>

H9. VECC notes that Issue #25 explicitly addresses the rate for export service and the associated revenues. Similarly the wholesale meter service rates/fees and revenues are linked to issues related to cost allocation and determination of the charge determinants and will be dealt with under Issue #24. Therefore the submissions in this section will be limited to Other Revenues[34] – excluding these two items.

H10. In the initial Application, forecasts External Revenues for the test years were $31.4 M, $32.7 M and $32.2 M respectively for 2020, 2021 and 2022[35]. These values were unchanged in the June 2019 Update.

H11. Hydro One Networks' forecast for External Revenues is broken down into four categories:

- Secondary Land Use – consists of revenues generated by charging land rentals to external parties for new license and lease occupations and subsequent agreement

[31] Page 69
[32] Exhibit I2, Tab 2, Schedule 1, Attachment 1
[33] VECC 53 c)
[34] Also referred to as External Revenues per Exhibit E, Tab 2, Schedule 1
[35] Exhibit E, Tab 2, Schedule 1, page 2, Table 2

renewals, as well as lump sum considerations for easements granted (e.g., water mains) and operational land sales completed (e.g., roadway)[36].

- Station Services – consists of revenues from external work (e.g., repairing electrical equipment (such as transformers, breakers and switches), specialty machining (spindles), protective relay installation, maintenance and calibration, coordinating services to reconnect modified systems to the network, as well as providing meter services and emergency services)[37].

- Engineering and Construction – consists of revenues from work performed for Hydro One Telecom[38].

- Other External Revenues – consists of revenues from providing telecommunications services to Ontario Hydro successor companies (such as lease of fibre), revenues from special transmission planning studies, customer shortfall payments (e.g. true-ups, temporary bypass), and other miscellaneous external revenues, including transfer price charges to Hydro One's affiliate companies[39].

H12. As seen in the following table[40], for the past four years (2015-2018) total actual External Revenues have exceeded the approved levels by an average of $12.7 M annually. In each year, more than half the difference was accounted for by the variance in revenues attributed to Secondary Land Use which is due, in part, to one-time unbudgeted transactions[41].

Table 1 – Summary of External Revenues

($ millions)	EB-2014-0140						EB-2016-0160						EB-2018-0130	
	2015			2016			2017			2018			2019	
	Proposed	Approved[1]	Actual	Proposed	Approved[1]	Actual	Proposed	Approved	Actual	Proposed	Approved	Actual	Proposed	Approved
Secondary Land Use	14.3	17.7	34.3	14.5	17.9	24.9	15.4	15.4	20.1	15.6	15.6	25.6	17.	15.6
Station Maintenance	7.2	7.2	9.5	7.3	7.3	6.2	5.3	5.3	3.9	5.3	5.3	4.6	4	5.3
Engineering & Construction	-	-	0.4	-	-	0.2	-	-	0.3	-	-	0.1	0.3	-
Other External Revenues	6.9	6.9	10.1	7.0	7.0	11.0	7.5	7.5	11.2	7.6	7.6	9.1	9.4	7.6
Totals	**28.4**	**31.8**	**54.3**	**28.8**	**32.2**	**42.3**	**28.2**	**28.2**	**35.5**	**28.5**	**28.5**	**39.4**	**31.3**	**28.5**
1 - Settlement, Issue 4. Are Other Revenue (excluding export revenue) forecasts appropriate?														

H13. Similarly, actual External Revenues for 2019 appear to be trending above the approved value for 2019[42].

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[36] Exhibit E, Tab 2, Schedule 1, page 3
[37] Exhibit E, Tab 2, Schedule 1, page 4
[38] Exhibit E, Tab 2, Schedule 1, page 5
[39] Exhibit E, Tab 2, Schedule 1, page 6
[40] Exhibit I, Tab 10 , Schedule 17 (VECC 17)
[41] Exhibit I, Tab 1. Schedule 150 (OEB 150) and Exhibit I, Tab 10, Schedule 19 (VECC 19)
[42] Actuals for the first half of 2019 are $14.5 M as compared to $18.4 M for the first half of 2018 (per JT 2.34, Q-07). The $18.4 M for the first half of 2018 represents 46.7% of the total External Revenues for 2018. In comparison, the actual $14.5 M for the first half of 2019 represents 50.9% of the approved 2019 value of $28.5 M.

H14. Hydro One Networks is proposing to continue the regulatory accounts that will capture differences between actual and approved External Secondary Land Use Revenues as well as Station Maintenance, Engineering and Construction and Other External Revenues[43]. This proposal means that any differences between forecast and actual other/external revenues will be eventually trued-up. VECC submits that Hydro One Networks' forecasts of other/external revenues for 20202 through 2022 are acceptable for purposes of setting the transmission rates in these years provided the Board approves the continuation of these regulatory accounts.

H15. In the event that the Board decides not to approve the continuation of these two regulatory accounts VECC submits that the level of other/external revenues for 2020-2022 should be increased by at least $7 M in each year, which is roughly equivalent to the minimum variance experienced over the last four years for which actual annual values are available[44].

H16.
H17. This is not it

I: Deferral & Variance Accounts

Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

Are the proposed new deferral and variance accounts appropriate?

I1. The LDC CDM and DR Variance Account for Transmission was established as part of the Settlement Agreement approved by the OEB in Hydro One's EB-2012-0031 Transmission Application. In the Settlement Agreement, Hydro One agreed to:

- "set up a variance account to track the difference between the forecast of 755MW for 2013 and 1158MWfor 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs"[45].

- "track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836MW in 2013 and 880MW 2014 (net of 317MW and 410MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account"[46].

I2. In its EB-2016-0160 Decision the OEB stated:

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43 Exhibit H, Tab 1, Schedule 1, pages 4-6
44 Exhibit I, Tab 10 , Schedule 17 (VECC 17)
45 Page 9
46 Page 10

"*The OEB finds that this account should not be closed at this time as proposed by Hydro One. The account was forecasted to generate a significant credit for ratepayers to the end of 2016 and these variances should continue to be recorded by Hydro One for the next two years. The OEB realizes that the IESO will no longer be providing actual peak savings information in those years. However, this fact should not automatically lead to the closure of the variance account. The OEB directs Hydro One to use its best efforts to obtain from other sources the peak savings information that it needs to determine the variances to be recorded in this account*."

I3. In its current Application Hydro One is proposing to recover the balance in the account calculated for 2017. VECC's concern is that in calculating the 2017 balance Hydro One has included the impact of more than just variance related to OPA-funded LDC delivered programs and Demand Response programs as approved by the Board. The calculation also includes: i) the impact of Codes and Standards, ii) the impact of Energy Efficiency (EE) savings from transmission connected end-use customers, iii) the impact of time of use rates and v) the impact of EE programs implemented by other parties such as Natural Resources Canada, Enbridge and Union Gas[47].

I4. Hydro One rationalizes the inclusion of these additional sources of savings based on the fact that the concern at the time of the EB-2013-0031 Settlement Agreement was around the total CDM included in Hydro One's forecasts[48]. While this may have been the "concern", it does not change the facts that:

- the variance account approved by the OEB was limited to the impact of: i) the difference between the forecast and the actual CDM savings related to the OPA-funded, LDC-delivered programs and ii) the difference between forecast and actual Demand Response impacts (net of those associated with LDC-delivered programs; and,

- the Board has not subsequently issued any decisions changing the original purpose/scope of the account[49].

I5. It is VECC's submission that scope of a regulatory account can only be changed with the approval of the Board. Furthermore, it is VECC's submission that the Board cannot retroactively change scope of a regulatory account as this would be akin to retroactive ratemaking. For these reasons VECC submits that the Board should deny the Hydro One its request dispose of the balance associated with the LDC CDM and DR Variance Account for Transmission as currently calculated. Rather, Hydro One should be directed to re-calculate the balance in the account consistent with the Account's approved definition and re-file for recovery in a future Application.

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[47] Oral Hearing, Volume 8, pages 113-117
[48] Oral Hearing, Volume 8, page 114
[49] Oral Proceeding, Volume 8, page 115

J: Cost Allocation

Is the transmission cost allocation proposed by Hydro One appropriate?

J1. Hydro One Networks' Cost Allocation methodology is the same as that accepted by the OEB in its EB-2016-0160 Decision. For purposes of the current Application the Cost Allocation methodology was used to allocate the proposed 2020 transmission rates revenue requirement to the proposed rate pools (i.e., Network, Line Connection and Transformation Connection). For the years 2021 and 2022, the proposed transmission rates revenue requirement was allocated to the proposed rate pools using the percentage split derived for 2020[50].

J2. During the interrogatory phase and the Technical Conference[51] VECC sought explanations for the changes in functional designation of assets as between the EB-2014-0140 and the current proceeding as well as the functional treatment of new assets added since the last proceeding. In VECC's view, Hydro One Networks has adequately explained the changes that have occurred as between the two applications.

J3. In its EB-2016-0160 Decision[52] the OEB approved the elimination of the Wholesale Revenue Metering functional category and the inclusion of the associated assets in the Transformation Connection functional category. In the same Decision the OEB also approved Hydro One Networks' proposal to maintain the Wholesale Meter Service fee at $7,900 per meter point. In the current Application, Hydro One Networks is proposing that the Wholesale Meter Service fee be maintained at $7.900 per meter point[53].

J4. VECC has no issues with Hydro One's proposed transmission cost allocation or its proposed Wholesale Meter Service Fee.

K: Export Transmission Rates

Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

K1. Hydro One Networks proposes to maintain the Export Transmission Service (ETS) Rate at its currently approved level of $1.85 / MWh[54]. Forecast export volumes for 2020 (19.4 TWh), 2021(19.4 TWh) and 2022 (19.6 TWh) are calculated based on a three year rolling average of historical export volumes[55]. The resulting forecast export revenues for 2020, 2021 and 2023 are $35.9 M, $35.9 M and $36.3 M respectively.

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[50] Exhibit I1, Tab 1, Schedule 1, pages 2-3
[51] Exhibit I, Tab 10, Schedules 47, 48, 49, 50, 51 & 52 and JT 2.34, Q-15 & Q-16
[52] Page 71
[53] Exhibit I2, Schedule 3, Tab 1, page 2
[54]Updated Exhibit I2, Tab 4, Schedule 1, page 3
[55] Exhibit I, Tab 10, Schedule 55

K2. As part of the Application Hydro One Networks updated the 2015 Elenchus cost allocation study utilizing the latest available information[56]. The resulting ETS rate is $1.25[57]. In the Application[58] Hydro One explained that its proposal to maintain the ETS rate at $1.85 was based on: i) the fact this value was established as part of the Settlement Agreement in EB-2014-0410 and ii) a decrease in the ETS rate will negatively impact the transmission rates that Ontario customers pay and could be perceived as benefiting customers in neighbouring jurisdictions at the expense of Ontario consumers[59]. During the oral proceeding[60] Hydro One expanded on its rationale:

> *"But at the end the ETS rate has never been set directly from a result of a study. Instead, it has always been set through settlement agreement or OEB decisions. And the current rate of $1.85, as we just talked about, is a negotiated rate, established as part of Hydro One's 2015-2016 transmission rate case.*
> *Now, again, because of the history of how this ETS rate is set, the nature of this negotiated rate, and also the fact that this Elenchus recommended methodology was never tested or examined by the Board and the intervenors in the settlement agreement, Hydro One does not believe that it is appropriate to just use this study in this application and set the ETS rate directly from this study."*

K3. During the oral hearing Hydro One also noted a number of issues regarding the Elenchus Study as filed and its underlying methodology:

- The initial Elenchus Study included multiple scenarios which were never fully examined or tested[61] and at least one of these yielded results that were considerably higher[62].
- Elenchus did not undertake a jurisdictional review of how transmission rates are set elsewhere[63]. In this regard Hydro One's witnesses noted that, with respect to the charges that would apply to exports into Ontario from neighbouring jurisdictions, a report prepared for the previous Application indicated that all of those charges were well above the $2[64].
- Hydro One had only "qualified" acceptance of Elenchus' assumption that none of the asset-related network costs should be allocated to exports on the basis exports were interruptible.[65]. On this point Hydro One noted[66] that export transactions are scheduled

[56] The "latest available information" consisted of the 2018 system peak and export load data, forecast 2020 ETS sales of 18.8 GWh and Hydro One's proposed 2020 revenue requirement per Updated Exhibit I2, Tab 4, Schedule 1, pages 2-3
[57] Updated Exhibit I2, Tab 4, Schedule 1, page 3
[58] Updated Exhibit I2, Tab 4, Schedule 1, page 3
[59] Exhibit I2, Tab 4, Schedule 1 page 3
[60] Volume 7, page 177
[61] Volume 8, page 147
[62] Volume 8 pages 152-153
[63] Volume 9, page 9
[64] Volume 7, page 171
[65] Volume 8, page 152
[66] Volume 9, page 8

and they're treated just as firm domestic load even if it causes transmission congestion. It is only at the curtailment area where there is potentially a different treatment (i.e., If there was an emergency, a security issue, a supply issue, then exports would be curtailed first).

K4. On this last point (i.e., regarding exports being interruptible) VECC notes that Elenchus' approach relied[67] on the Board's EB-2012-0031 Report[68] where the Board stated:

> *"The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be viewed as a separate class. Second, absent a cost allocation study, the degree to which the differences in service should be reflected in a rate differential is unknown*."

K5. What is important with respect to the EB-2012-0031 Decision is that it only noted exports were treated more as interruptible load and therefore should be treated differently from firm load. It did not conclude that they were fully interruptible or that they should not be allocated any shared asset-related costs[69].

K6. Indeed, in this regard exports can be viewed somewhat similar to 3rd party pole attachments (e.g. telecom companies), which use distribution utility poles that have been built to deliver power to the distributors' electricity customers but which the other parties also seek to use. In this case, the Board has recently determined[70] that the rates charged to 3rd party attachers should include asset-related costs associated with shared component of the pole[71].

K7. As well as the points raised by Hydro One, VECC notes there are other issues/outstanding concerns regarding the Elenchus methodology:

- In several of the responses to questions posed in EB-2014-0140 (e.g., TCJ2.01) it was stated that "The Elenchus model is a simple cost based model" and it was acknowledged that refinements could be made. However, none of these refinements were incorporated into the Elenchus model filed in the current proceeding[72].

- During the current proceeding Elenchus' use of the 12CP allocation factor (as opposed to a 1CP allocation factor) has been questioned[73]. On this point, it is noted that the use

[67] Volume 9, page 6
[68] Page 5
[69] Volume 9, page 7
[70] EB-2015-0304
[71] Volume 9, pages 12-13
[72] JT2.34-Q20
[73] JT1.36-Q2 and Volume 8, page 154

of a 1CP allocation factor would increase the costs allocated to the exports in the Elenchus study[74].

- More fundamentally, the Settlement Agreement in EB-2014-0140 stated that: "*agreement on the level of ETS rate of $1.85 per MWh shall not be construed as acceptance of the methodology, assumptions, or scenarios used in the Elenchus Study". The Agreement further stated that "because this is the first case where a cost allocation study was filed in evidence to inform the ETS Rate, the parties observe that the cost allocation methodology proposed by the Elenchus Study remains untested and the parties do not necessarily agree with that methodology. The parties therefore agreed on the ETS rate on the understanding that the methodologies, assumptions and scenarios used in the Elenchus Study do not have precedential value and may be challenged in subsequent proceedings.*"[75]

K8. For the above reasons, VECC submits that the updated Elenchus methodology results filed in the current proceeding should not be used as the basis for the ETS rates and the Board should accept Hydro One's proposal to maintain the rate at $1.85.

K9. Hydro One has derived the ETS revenues using the proposed rate of $1.85/MWh and the three year historical rolling average volume of electricity exported from Ontario[76]. The export volumes used in the calculation for 2020 were 19.4 GWh[77] resulting in a 2020 ETS forecast revenue of $35.9M.

K10. During the proceeding, Hydro One indicated that its best estimate as to the 2020 export volumes was 18.8 GWh, a figure based on 2018 actual volumes[78]. This resulted in some discussion during the oral proceeding as to why the 18.8 number was not used in the derivation of the ETS revenues[79]. VECC notes that recently available data regarding actual 2019 ETS volumes indicates that, as of the end of September 2019, actual 2019 ETS volumes were 15.1 GWh as opposed to 14.0 GWh for the same period in 2018[80]. As a result if one were to use the more recent 2019 actuals as the basis for the 2020 forecast, the trend would suggest a value higher than the 19.4 GWh used in the export revenue derivation[81]. VECC notes that it is this year to year variability that initially led to Hydro One using a three-average for purpose of forecasting ETS volumes and revenues[82], recognizing that any differences are captured in a variance account.

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[74] JT1.36-Q2 b)
[75] Exhibit I, Tab 10, Schedule 54 a)
[76] Exhibit I2, Tab 4, Schedule 1, page 3
[77] Exhibit I, Tab 10, Schedule 55 b)
[78] Volume 7, pages 192-193 and Volume 9, page 14
[79] Volume 7, page 197
[80] J8.4
[81] 2019 volumes to date are more than 1 GWh than 2018 actuals. Adding 1 GWh to 2018 actuals yields 19.8 GWh – a higher value than the 19.4 GWh used by Hydro One.
[82] Volume 7, page 198

K11. VECC submits that the Board should accept Hydro One's ETS revenues forecast.

Reasonably Incurred Costs

VECC submits that it has acted responsibly and efficiently during the course of this proceeding and requests that it be allowed to recover 100% of its reasonably incurred costs.

ALL OF WHICH IS RESPECTFULLY SUBMITTED