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February 3, 2017

VIA MAIL and E-MAIL

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

Dear Ms. Walli:

Re: Vulnerable Energy Consumers Coalition (VECC) Final Submissions
Hydro One Networks Inc. 2017 and 2018 Transmission Cost-Of-Service
EB-2016-0160

Please find enclosed the submissions of the Vulnerable Energy Consumers Coalition (VECC) in the above noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

cc: Erin Henderson, Senior Regulatory Co-ordinator
regulatory@hydroone.com

EB-2016-0160

ONTARIO ENERGY BOARD

Application for electricity transmission revenue requirement and related changes to the Uniform Transmission Rates beginning January 1, 2017 and January 1, 2018

FINAL SUBMISSIONS

ON BEHALF OF THE

VULNERABLE ENERGY CONSUMERS COALITION (VECC)

February 3, 2017

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Hydro One Networks Inc. EB-2016-0160

2017-2018 Transmission Revenue Requirement Application

Submissions of VECC

Introduction

Hydro One's application for approval of its 2017 and 2018 revenue requirement which will determine UTR for 2017 and 2018 provides for relatively modest increases in rates for electricity customers. The estimated bill impact for an average residential customer (750kWh/month) is 1% in 2017 and 2% in 2018. The principle concerns that arise out of the approval of Hydro One's transmission revenue requirement deal with the approach to the components of that revenue requirement on a going forward basis in the "new" Hydro One.

In reviewing the evidence filed by Hydro One in this proceeding and the testimony given in the lengthy hearing that dealt with the same, there are some evident difficulties associated with the drawing of conclusions to set the revenue requirement based upon the record. These difficulties revolve around the resolution of what appeared to be conflicting or confusing evidence and Company positions associated with key issues. These include:

1. A key element of the application involves a significant ramp up in capital spending from the $844.7 million (M) in 2014 actuals to $1076.2 M in 2017 and $1,122.2 M in 2018. The largest increase occurs in the area of sustaining capital expenditures which reflect an approximate 30% increase in 2017 and a 32% increase in 2018[1]. Sustaining capital expenditures address in the main, reliability and performance of the transmission system. The ramp up appears to respond not to documented system historical reliability performance, but to objectives based on desired outcomes derived from the newly developed reliability risk model and perceived customer preferences.

[1] Tr. Vol 8, p.4

2. The new leading outcome measure – the reliability risk model – is a principal influence on both the customer engagement process that is part of the stakeholder engagement step in the capital budget approval process and the candidate selection process. It is based on statistical probabilities derived from age not asset condition. The model cannot be shown to have validity using historical data nor shown to have an effect on actual reliability.

3. The customer engagement process while directionally does show a priority concern with reliability is problematic in its use by Hydro One to support changes to the revenue requirement to accommodate a substantially increased capital program. Apart from the influence of the introduction of the reliability risk model in the customer engagement discussion, the reliability/rates equation inherent in the consultation is muddled by the fact that the vast majority of the actual payers of the rates generated by Company's revenue requirement (LDC customers) were not involved in the consultation (without necessarily suggesting their inclusion).

4. The assessment of the performance of Hydro One from an efficiency and productivity standpoint is clouded by problems in data comparability with other transmitters, the lack of a an accepted unit cost metric and the inability or unwillingness to normalize for volatility caused by weather- a principal cause of outages.

5. While the principle of insulation of customers from the transformation of the status of Hydro One has been ostensibly accepted, it is less than clear, given the increase in expenditures whether the revenue requirement has actually been sterilized of the effect of the transformation particularly when it comes to increased executive compensation costs.

6. The budgetary request upon which the capital request of the revenue requirement is based includes projects that have not been signed off. There seems to be a somewhat loose fit between what is approved and what is put in service.

VECC has largely resolved these evidentiary problems and conflicts in these submissions in the following manner:

(i) While the revenue requirement should respond to transmission system needs, particularly in the area of sustaining capital, the pacing of the response should reflect a more reasonable time frame for renewal and more congruent with actual performance ;

(ii) The reliability risk model must be further tested if it is to become a determinant in the fashioning of the capital expenditure envelope;

(iii) Customer engagement efforts should incorporate, where possible, the views and preferences of the distribution utility customers that ultimately pay UTR as well as those of LDCs and large industrials;

(iv) Historical reliability performance metrics should be normalised for weather and Hydro One should develop a unit cost comparison that fairly evaluates its year by year performance;

(v) Hydro One's reporting practices should reflect the fate of those projects included in revenue requirement. The portfolio contingency observations of the Navigant report should be studied with a view to more efficiently managing the delivery of capital projects, and a performance metric similar to the RCE should have financial impact for Hydro One.

(vi) The financial impacts of the change from government owned to investor owned utility that benefit only the investors should be thoroughly extracted from the costs of improvements in overall corporate efficiency that actually benefit ratepayers.

(vii) Hydro One has experienced 5 straight years of relatively substantial over-earning (provided 2016 year end projections are correct). While this is ascribed to weather, earnings sharing of weather normalised over-earning amounts should be considered. This measure could also provide additional assurance for ratepayers that their interests are protected in the “new” Hydro One.

While some of the matters discussed do not fall neatly within the subject issue, VECC has followed the Board approved issues list in making its submission that develops the above themes.

A. GENERAL

Issue #1: Has Hydro One responded appropriately to all relevant OEB directions from previous proceedings?

Hydro One response to this issue is found at Exhibit 1, Tab 4, Schedule 2. The Utility notes that the prior proceeding was subject to a comprehensive settlement. Aside from adjustment to certain revenue requirement items the Settlement Agreement had two substantive going-forward requirements:

1) a Net Cumulative Symmetrical Variance Account for 2014, 2015, and 2016 to track the impact on revenue requirement of any ISA (in-service additions) shortfall;
2) complete an independent Transmission Cost Benchmarking Study that will be filed with the next Transmission rates application;
3) the establishment of an LDC CDM and Demand Response Variance; and
4) the establishment of a symmetrical variance account to track any differences in Other External Revenue.

While we have specific submissions on the content of some of these items, in our submission Hydro One has met its commitment from the prior proceeding.

Issue #2: Are all elements of the proposed 2017 and 2018 revenue requirements and their associated total bill impacts reasonable?

No. Our submissions below detail what adjustments should be made to the 2017 and 2018 revenue requirement. In addition, VECC is concerned with the pattern of over-earning shown by Hydro One returns over the past five years.

	2012	**2013**	**2014**	**2015**
Allowed ROE	9.42%	8.93%	9.36%	9.30%
Actual ROE	12.41%	13.22%	13.12%	10.93%
Variance	**2.99%**	**4.29%**	**3.76%**	**1.63%**

Source: Exhibit I/T2/S30

When asked about these overearnings one response was that "*over the course of 2012-2014 cumulative in-service additions were less than planned*.[2]" On the other hand, weather was cited as the principle cause for this phenomenon[3].

> MR. JANIGAN: Okay. I wanted to deal with as well the part of the incentive that's dealt with by way of total earnings of the company. And on page 14 of my compendium
>
> -- I believe Mr. Rubenstein referred to this earlier -- that for the fifth year in a row Hydro One transmission will exceed its regulated rate of return. Am I correct on that?
>
> MR. VELS: That would presume that the nine months of performance in 2016 continued at the current rate.
>
> MR. JANIGAN: And as I understand the answer on page 14 to this interrogatory by BOMA, number 30, that the primary reason for the overearning has been weather.
>
> MR. VELS: That's correct.
>
> MR. JANIGAN: Do you have weather-normalized figures for your ROE?
>
> MR. VELS: No, we don't.

In fact, the correspondence from Hydro One counsel, dated November 13 2016, and filed with the Board notes the following[4]:

[2] Exhibit I/T2/S30
[3] Tr. Vol. 1 pp.187-188
[4] Exhibit K1.6 p. 13

> "Year to date actual ROE for the third quarter of 2016 is approximately 8.8% or 11.7% annualized.
>
> Higher demand, experienced during a warmer than normal summer, contributed 0.8% annualized to the ROE. After adjusting for weather, the achieved annualized ROE is 10.9%, which is approximately 1.7% above the allowed ROE of 9.19%."

It is difficult to figure out how the weather related increment referred to above was calculated if Hydro One does not weather normalize its ROE.[5] It also appears to indicate that, for 2016 at least, a healthy portion of the over-earning is not attributed to weather.

In VECC's view it makes sense for the Board to consider implementing a weather normalized earnings sharing mechanism associated with earnings above the allowed ROE. It is particularly apt given the need for assurance to ratepayers of the protection of their interests following the transition from a publicly -owned to an investor- owned utility coupled with its recent earnings performance.

Issue #3: Were Hydro One's customer engagement activities sufficient to enable customer needs and preferences to be considered in the formulation of its proposed spending?

Partially. Board staff has made detailed arguments with respect to Hydro One's customer engagement. We share some of Staff's concerns, which are addressed below. However it is also important to understand that the Ipsos Reid customer engagement consultation represents only one, arguably small, part of the consumer engagement undertaken. As detailed in Exhibit B1, Tab 2, Schedule 2 Hydro One has numerous outreach programs, working groups and committees.

[5] It also casts doubt about any other expressed Company inability to weather normalize for outages or equipment failure.

The conclusions of Hydro One as to its customer's preferences are listed below[6]:

- Transmission customers need predictable, reliable power at the current level of performance or higher, particularly, with respect to frequency of interruptions, especially large industrial end users who otherwise face unacceptable economic, environmental and health and safety risks;
- Transmission customers prefer competitive or low cost of service, but not at the expense of deteriorated service;
- Transmission customers need improved outage planning and notification (specifically, minimization of the number of planned outages and improved communication);
- Transmission customers expect continuing communication of Hydro One Transmission's long-term investment plans; and
- Transmission customers need a greater focus on power quality driven by the increased sensitivity of their equipment.

There is little surprise in the conclusions that arise from this engagement. Other than the insight as to customer concern for power quality the remainder would appear obvious and of little contention. They are, in the vernacular, "motherhood" issues. With respect to customer concerns expressed on power quality we note that Hydro One has taken specific steps, including a Power Quality Working Group to try and address these issues.[7]

The main criticism of the customer engagement process, as noted by Staff in their argument, would seem to be that the choices presented to these customers were based on a model that incorporated the concept of "reliability risk" as a measure of the impact of sustaining capital spending. As Hydro One concedes, there is no direct relationship between spending and reliability performance:

[6] Exhibit B1/T2/S2, pg.10
[7] See for example Undertaking J4.4

> MR. PENSTONE: Right. So this is why we use the term it's reliability risk. We can't say with any sense of authority there is a direct linkage between investments and reliability, SAIDI and SAIFI. Reliability depends on many other factors.[8]

While it was said that most customers consulted understood the difference, there is some discussion of confusion or lack of information expressed by some participants associated with the difference between reliability risk and reliability performance.[9] Moreover, a slide statistic from the consultation that cited a 300% increase in the duration of outages between 2013-2015 failed to distinguish between outages caused by equipment failure and planned outages that were associated with sustaining capital projects.[10]

> MS. BLANCHARD: Right. So there the is a substantial increase in planned outages in those three years, 2013 to 2015, and that is because you doing a lot more sustaining investment?
>
> MR. McLACHLAN: Correct.
>
> MS. BLANCHARD: Okay. And so would you agree with me that, for example, if I am looking at 2014, it's a lot more planned outages relating to sustaining investment, the numbers 356, relative to 194 unplanned?
>
> MR. McLACHLAN: That's correct. That's what the slide shows, yes.

VECC shares Staff's view that the reliability risk model and its current application lack a persuasive basis in fact. The model was apparently developed in 2016 and rushed into the customer engagement process. Like Board Staff, VECC also sought to understand why this model could not be tested for its veracity.[11] Staff has given this testing the nomenclature of "back-casting". More simply, the model should be validated in some fashion before it is a leading outcomes measure. No such evidence was offered. In VECC's view , the model's role in informing customers of the need to spend more to ensure future reliability, or to choose candidate investments is at the very least premature. The nub of the matter is succinctly drawn out by Member Dr. Elsayed:

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[8] Tr. Vol. 1, p.70
[9] Tr. Vol. 4. pp. 35-36
[10] Tr. Vol. 4, p9 and p. 11
[11] Tr. Vol. 8, p.21 and Exhibit I/T12/S2 & I/T1/S14

DR. ELSAYED: My question is: How would you determine then, in turn, what that reduction would mean in terms of actual reliability, as opposed to just reliability risk? That's why I am struggling with establishing, that relationship. And if you need more time to think about it that's fine.
But the question that I am putting before you is: Is there any way, using either historical data or otherwise, to establish a relationship between reliability risk and actual reliability? And I don't need the answer right now.

MR. PENSTONE: Well, I can almost give you an answer right now; it's that I don't know. I mean, it would be easy -- if we were able to come up with a model to estimate the direct impacts on reliability of investments being made or not made, we would have presented it as part of the application.
But as we have described in the application, the actual reliability that's experienced by our customers is also influenced by these other external factor, and we also recognize the fact that even though assets are at their end of life, it doesn't mean that they are going to fail tomorrow.[12]

Hydro One offers no answer because none exists, and as Staff states, the inability to draw a relationship between reliability and "reliability risk" makes it a misleading construct as part of its customer engagement. It appears to have been a central theme particularly as it pertains to potential rate increases related to an expanding rate base.

In addition to the potentially misleading outage information given in the Ipsos consultation noted above the major difficulty with Hydro One's evidence with respect to reliability as a whole is that the causes of interruptions are not detailed. What is clear, however, and as shown by the table showing 2015 outages is that a single event can be the cause of a disproportionate amount of unreliability.

Category	Equipment Type	Cause	No. of Outages	Contribution to Annual Unavailability
Transmission Line	Transmission Line	Defective Equipment	1	42%
Station Equipment	Power Transformer	Defective Equipment	3	11%
	Circuit Breaker		6	25%
	Shunt Capacitor		1	3%
	Shunt Reactor		1	3%

Source: Exhibit I/T1/S12/pg.2

[12] Tr. Vol. 5, p.128

This would seem to argue for some use of a predictive model. it is our submission that Hydro One should be required to present at its next application a survey of best practices for predictive reliability modelling. The Utility should also, in our view be required to employ existing data to test the veracity of its modeling. Finally, it seems to us that there is little point in such an exercise if it is not integrated into the actual deployment of capital. Given all this at this conjecture, it would be premature to argue for what reliance can be put on predicative reliability modeling in this case.

VECC is aware that the major stumbling block in the development of such a model is the volatility caused by weather. The development of a weather normalised model would seem appropriate to assess the impact of capital investment on real measurement of performance[13].

In addition to the problems with the use of the risk reliability model to determine customer preferences in a rigorous fashion, there is a disconnect between the customer engagement here, and the achievement of one of the principal goals of the exercise, which is to solicit the views of customers who must pay the utility rates. VECC acknowledges the difficulty of providing feedback from distribution customers of LDCs on transmission issues. Nonetheless, they are responsible for contributing 92% of Hydro One's Revenue Requirement though UTR rates. LDCs are likely to be more concerned with the constant delivery of supply rather than the cost of transmission which is passed on to their customers. Accordingly, an application for increased rates for capital expenditures that may have an effect of maintaining reliable delivery might take a priority over lower rates. While the LDCs views have significance, they are only one aspect of informing the rates/service reliability balance.[14]

[13] If it doesn't already exist – see section on over-earnings by Hydro One

[14] It is notable that the importance of the customer engagement process seemed to shrink as the oral hearing continued. At Tr. Vol. 1 p.28, Mr. Penstone noted ; "As Mr. Vels and Mr. Hubert have already referred to, a customer engagement process was undertaken. This ensured customers' needs and preferences informed the development of the transmission plan" At Tr. Vol 6, p.65 Mr. Penstone describes the capital investment planning process; "And then again the third element of it was making adjustments, relatively minor adjustments as it relates to the customer engagement".

This does not mean the customer engagement process is flawed without the inclusion of distribution customers. However, LDCs and informal communication mechanisms don't necessarily represent the views of the distribution consumers that pay the rates.

We would also note that in this application the integration of the Regional Planning exercise was peripheral. Yet it seems to us the implementation of these plans should be separately developed and it should be shown that the transmission utility is effectively implementing them. It is also not clear to us from the evidence why regional planning does not inform sustainment programs (or why it should not in the future).

VECC understands through its intervention in distribution applications that there are in fact a number of issues arising between LDC and Hydro One TX, many of which have significant cost implications to end-use customers. Again, these are peripheral to non-existent in this application. Hydro One's meetings with local distribution companies and any issues arising from those meetings should, in our view, be documented in future filings of the transmission utility.

VECC suggests the Board reconsider and if necessary, redirect the efforts of Hydro One Transmission with respect to customer engagement. The transmission arm of the utility serves a known number of local distribution utilities, a small number of directly connected customers and provides inter-tie services with other jurisdictions. This discrete set of customers allows the Company to have more intimate and informed engagement compared to a local distribution utility servicing thousands or hundreds of thousands of customers.

The gap between engaging ratepayers in general and the customers of Hydro One (LDCs and direct connects) is broad. All electric local distribution utilities report SAIDI/SAIFI on the basis of with and without loss of supply. Loss of supply is the measure for these utilities of the reliability of the transmission system[15]. The difficulty in engaging distribution customers directly is that the surveyor must somehow untangle the reliability of the distribution and transmission system when seeking a ratepayer's opinion as to the reliability of their service and their appetite for paying for new

[15] This is a simplification as In fact it is more complicated because of the fact that many non Hydro One customers are supplied by low-voltage assets.

investment. As we have heard in this proceeding for some customers, transmission system reliability is critical whereas for many others with redundant supply points it is of much less consequence. It is probably the case that transmission reliability matters more to the ratepayer of Chapleau Public Utilities Corporation than to a customer of Toronto Hydro simply because the odds of transmission asset failure affecting them is so much different.

Conceptually, there should be a relationship between the Customer Delivery Point Performance (CDPP), LDC SAIFI/SADI supply related outages and the reliability modeling that Hydro One undertakes. The Ipsos and other popular survey modeling is best employed, we would argue, for distribution services. Even there it is fraught issues, none larger than the tendency to project the view that "if we don't spend what we tell you we should spend the sky will fall." In order to provide customers with real choices and trade-offs with true consequences the utility must have a refined understanding of its assets, their condition and the implications of their maintenance and replacement.

B. TRANSMISSION SYSTEM PLAN

Issue #4. Does the Transmission System Plan adequately address customer needs and preferences?

Notwithstanding our difficulties with the content and interpretation of the customer engagement plan, VECC believes that the Transmission System Plan (TSP) directionally lines up with the concerns of the 200 or so transmission customers. In fact, the plan overcompensates for reliability based on a flawed analysis which attempts to translate reliability concerns into capital expenditures. There is, in short, no substantive evidence that customers are not satisfied with the current level of transmission service reliability. Nor is their strong evidence of impending reliability issues.

Furthermore, the Hydro One argument that advances the theory that customers are solidly behind the view that Hydro One requires a significant increase in its capital budget to maintain the current level of reliability is significantly flawed and simply wrong.

In fact, in this proceeding only two salient new customer views came forward. One is that large customers are concerned with power quality. The second, as expressed by Anwaatin First Nations, is that customers subject to the inherent higher risk of the northern radial transmission system, seek assurances of investments to mitigate transmission interruptions.

Issue #5: Does Hydro One's investment planning process consider appropriate planning criteria? Does it adequately address the condition of the transmission system assets?

No, Hydro One's transmission asset investment planning is a bit in disarray, or at the very least rather incomplete in its explanation and execution.. Less than a year before the filing of its current application proposing a substantial ramp-up (and before the discovery of its risk reliability model) Hydro One was projecting a decline in capital expenditures:

> MS. Blanchard referring to Exhibit I, tab 9, Schedule 2, Attachment 1.)
>
> So this material was issued at the end of October, and it was included in the prospectus, … we are showing a projected capital expenditures for the years 2015 through 2019.
>
> MS. BLANCHARD: Right. Okay. But you will agree with me, though, looking here, that, at the time, your best information was that capital expenditures were actually going to decline for transmission between 2015, a peak of 899 million in 2015, declining down to 832 million in 2019?
>
> MR. VELS: That is what's reflected there. [16]

This is also evident from the application and subsequent testing of the evidence. Staff in their argument have noted how new evidence as to the process of capital planning arose throughout the proceeding and during the oral hearing. We agree. Contrast, for example, the five step process detailed in the main body of evidence. Here planning is described as taking into account defined business objectives (one of which "sustainable

[16] Tr. Vol 2. Pp. 43-44

managing the environmental footprint of operations" is not touched upon) and subject to a five step process[17]:

(1) review of the system;

(2) consideration of additional factors including business objectives ;

(3) creation of a portfolio of candidate projects;

(4) optimization; and

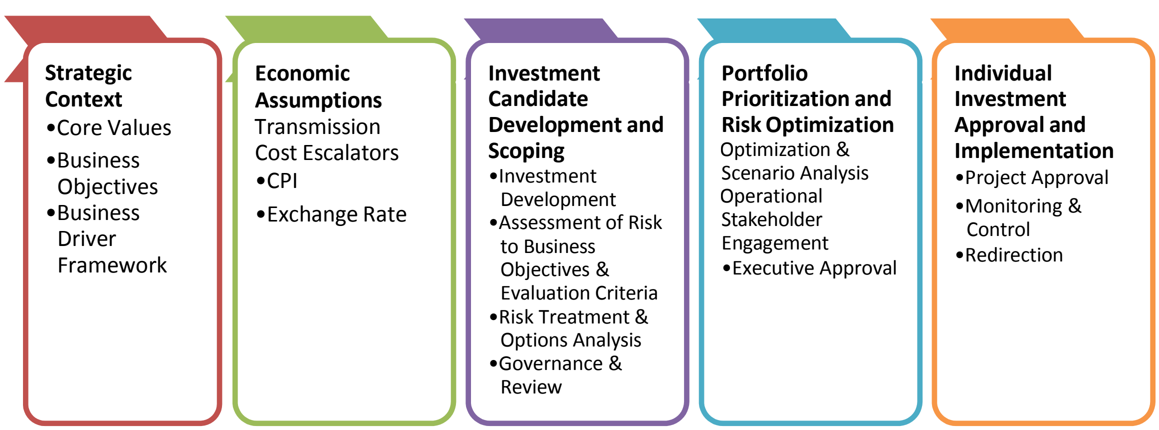
(5) assessment of the outcomes.

In its Argument-in-Chief seven stages of planning are described:

(1) Strategic Context
(2) Planning Assumptions
(3) Needs Assessment
(4) Investment Development
(5) Investment optimization
(6) Investment Approval and Implementation
(7) Performance Reporting

And we are referred to in support of this description evidence showing yet another, slightly different description:

Figure 1: Investment Planning Process[18]



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[17] Exhibit B1/T2/S4/pgs. 4-6
[18] Exhibit B1/T2/S7/pg.1

One thing we can certainly agree with is that "*Hydro One's investment planning process is not easily distilled into a simple, entirely linear description. There are many different facets of the needs identification process which interact with each other and can happen concurrently*[19]"

We are told that Hydro One utilizes "Expected Service Life" to assist in identifying assets as candidates for investment, but we also are told that while "*at a fleet level, asset age is used as a proxy for the probability of asset failure and the need for replacement. Quantitative data demonstrates the historical relationship between asset age and failure. This data has informed Hydro One's reliability risk model. However, as noted above, specific investment decisions are not based on age, but through the Asset Risk Assessmen*t[20]

We also know that some aspects of the capital plan, notably development capital, are subject to Regional Planning requirements and therefore non-discretionary in nature.

Between 2012 and 2015 Hydro One Transmission had capital budgets which averaged around $820 M. The average spend over 2017 and 2018 is near $1.1billion or an increase of 34%. The question that needs to be answered is whether the capital planning process supports the proposed significant increase in capital spending. In our submission, it does not. While it is true that Hydro One has taken steps toward a more rigorous and outcomes oriented planning process its Asset Assessment Methodology is not robust enough, its outcome metrics not yet integrated into the company's corporate culture and its predictive reliability modelling as yet untested and unused in planning.

We suggest to the Board that the statement in their argument that "*all the sustainment capital is vitally important*[21]" is more hyperbole than it is fact.

To return to the theme discussed in the customer engagement portion of this argument, while Hydro One is insistent that its reliability risk model is an outcomes measure only and not a driver of its capital investment planning, this does not seem to line up with its approach. That approach rejects the evidence at hand associated with reliability

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[19] Argument-in-Chief pg. 14
[20] Exhibit B1/T2/S4
[21] Argument-in-Chief, pg.45

performance and elevates a projection of the future at odds with the record. Its own evidence commissioned from Navigant shows the CEA comparison of Hydro One with other transmitters on standard reliability performance measures[22].

Figure 20. Sustained T-SAIFI-mc Comparison by the CEA

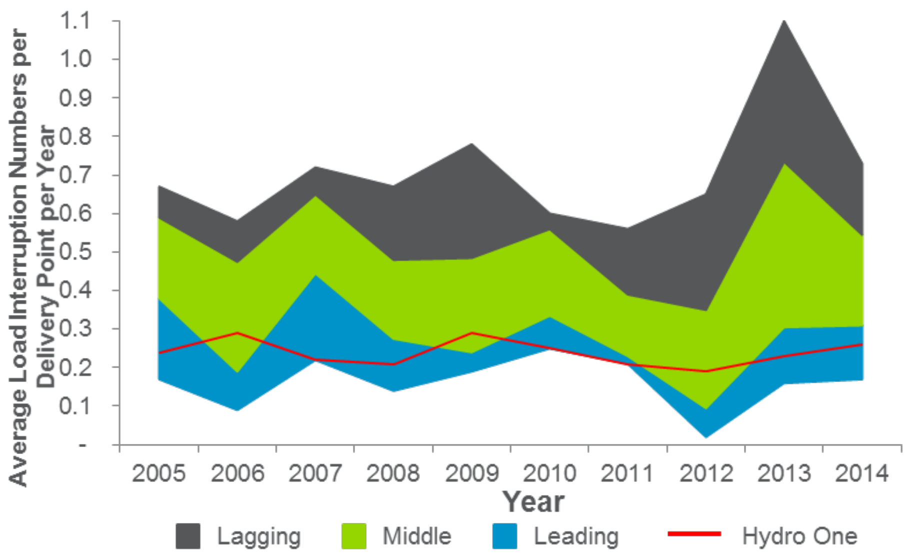
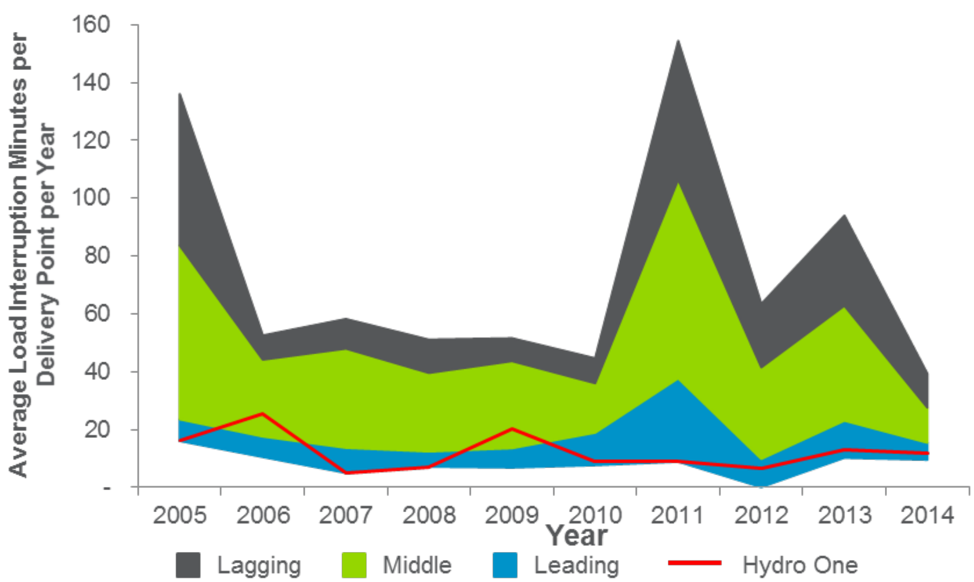


Figure 21. Sustained T-SAIDI-mc Comparison by the CEA



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[22] Ex. B, Sch 2,Tab 1 p.23

This issue was further explored with the Hydro One planning panel involving the CEA metrics documenting delivery point unavailability, unavailability of transmission lines, and forced outages[23]:

> MR. JANIGAN: Okay. And an I wonder if I could have you look at Volume 5 of the transcript between your discussion with Ms. Lea…
>
> And on the next page, page 111, down the top of the page it has:
>
> (MR.PENSTONE) So as Mr. McLachlan pointed in his recently made exhibit, equipment failures are increasing, yet reliability, to your point, doesn't seem to be affected. Our thesis is that while reliability hasn't been affected yet, the risk that it will be affected in the future needs to be addressed through the levels of capital expenditure that we're proposing."

And then further down the page, in support of effectively the position you indicate on line 26:

> "But I would like to draw your attention back to the exhibit that we just had up on the screen a minute ago for a statement, not this one, but the one that is Exhibit B1, tab 1, schedule 3, back to the charts we just showed about the unavailability of transmission lines, B 1, tab 1, schedule 3."

In this case, it would appear that the historical data supports neither of these assertions that equipment failures and the unavailability of transmission lines are increasing and system reliability is accordingly deteriorating. Hydro One witnesses attempted to heroically negate the importance of these metrics either by taking issue with what the measurements show or that the past doesn't necessarily predict the future ability to maintain high reliability performance. However, when five year rolling averages with the comparisons to the CEA are produced in the answer to Undertaking 8.2, any inference of deteriorating performance seems to be negated. This leaves the support for a greatly expanded capital program greatly dependant on the new reliability risk model.

[23] Tr. Vol 8 pp.7,8.9

Figure 11: Comparison of the Hydro One Five Year Moving Average for the Delivery Point Unreliability Index as Compared to the CEA Composite

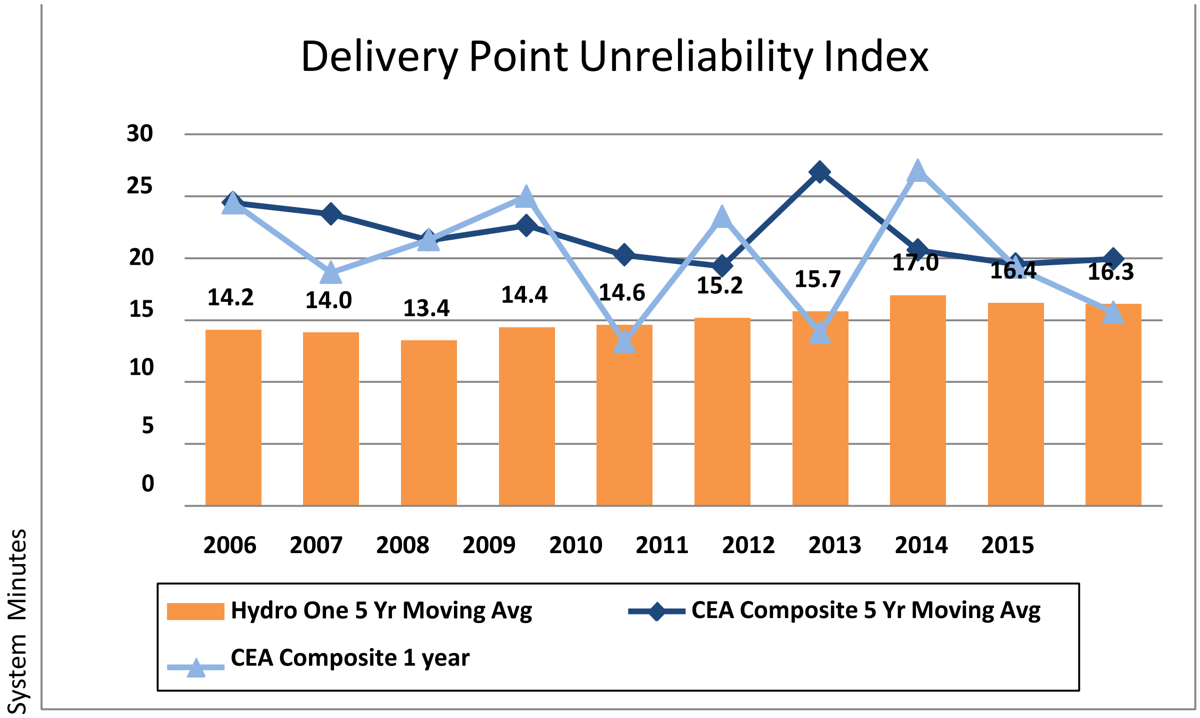


Figure 12: Hydro One Five Year Moving Average of the Unavailability of Transmission Lines as Compared to the CEA Composite Group

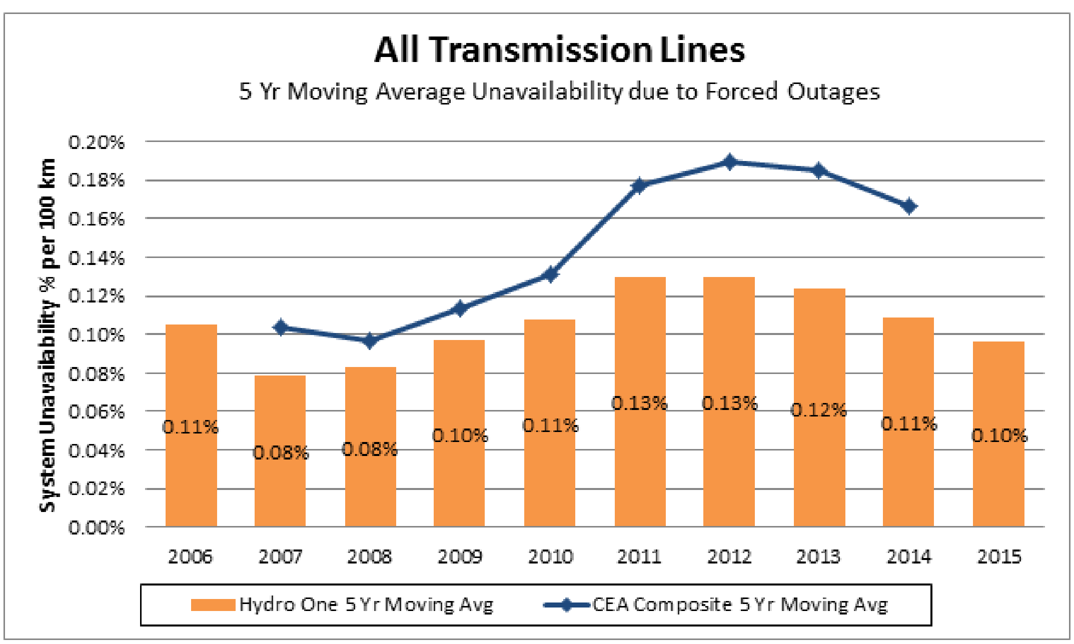
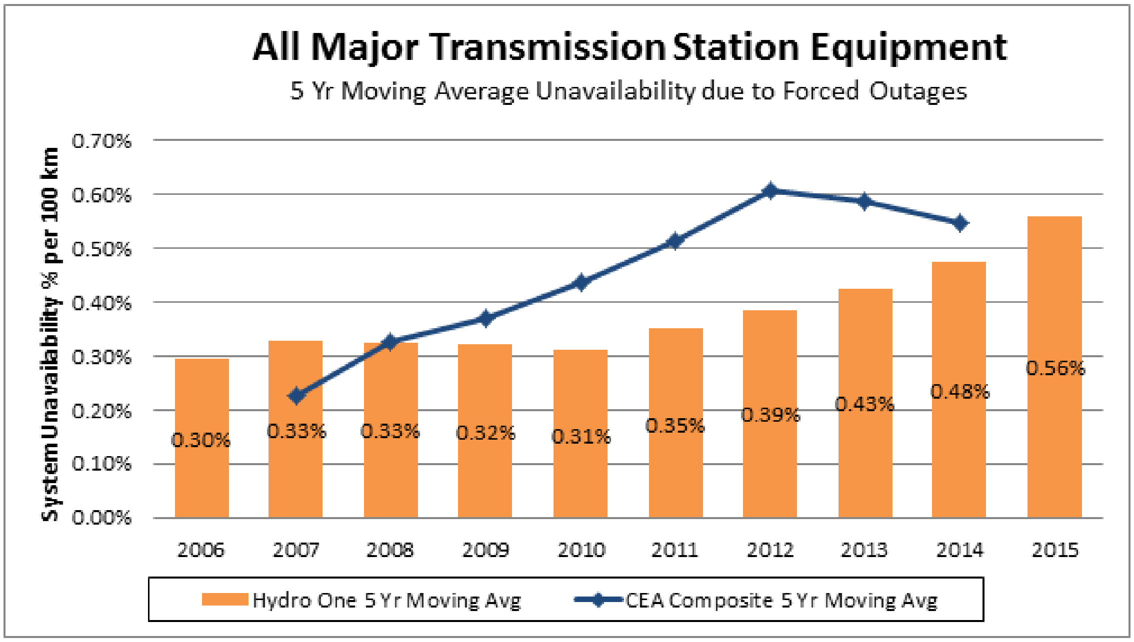


Figure 13: Hydro One Five Year Moving Average of the Unavailability of Major Transmission Station Equipment as Compared to the CEA Composite Group



Source: Undertaking J8.2

VECC is also concerned with varying degrees of accuracy and execution of the capital expenditure budget in Hydro One's revenue requirement. The variance between Board Approved and In Service is a matter of some concern particularly given the plea for a substantial ramp-up made in this application.

Table 1: In-Service Capital Additions 2014 – 2018 ($ Millions)

	2012 ISA Actuals	2012 OEB Approved	2013 ISA Actuals	2013 OEB Approved	2014 ISA Actuals	2014 OEB Approved	2015 ISA Actuals	2015 OEB Approved	2016 Bridge Projected	2016 OEB Approved	Test Years 2017	Test Years 2018
Sustaining	351.6	394.5	403.8	443.3	655.8	588.4	569.7	572.2	604.5	480.9	771.1	747.7
Development	793.8	1074.8	231.7	261.8	177.9	177.3	27.9	134.7	209.5	119.4	64.6	374.9
Operations	10.6	52.7	5.9	15.1	12.1	14.7	29.4	50.4	15.1	10.0	8.0	10.3
Common & Other	43.5	69.9	62.4	64	68.7	82.9	72.2	64.1	82.6	63.1	87.8	76.8
Total	**1199.5**	**1591.9**	**703.8**	**784.2**	**914.5**	**863.3**[1]	**699.1**	**821.3**	**911.7**	**673.3**	**931.4**	**1,209.7**

Source: Exhibit I/T3/S47

In VECC's view, some of this delta between approved and in-service may be attributed to the varied state of projects submitted for approval in the revenue requirement. As discussed further below, projects are included that don't have sign off on the final stage Business Case Summary and linger in the list of the Company's capital projects from rate case to rate case.[24]

> MS. LEA: Okay. So my question is if you are still awaiting business case approval for possibly many of these projects, how can this Board and the ratepayers we protect be confident that the portfolio the Board is approving is the one that Hydro One will eventually build?
>
> MR. PENSTONE: So, Ms. Lea, our evidence is based upon projects that we expect to undertake. They are forecasts.
>
> Based on those forecasts, this enables the Board to actually approve a revenue requirement as opposed to actually authorizing individual projects to be undertaken. I believe that's accurate.

VECC submits that it is necessary to ensure at a minimum, a higher percentage of execution ready projects are in the portfolio to be approved and that performance metrics incent their completion to in-service status.

Issue #6: Are the proposed 2017 and 2018 Capital Expenditures for Sustainment, Development and Operations appropriate?

Having concluded that the planning process does not support a 34% increase in capital spending, the next question is what is a reasonable in-service asset increase for 2017 and 2018 rate years?

Board staff have proposed an reduction of $136.56 million in each of the two years to be applied on a non-specific basis. The result of this would be to make the 2017 and 2018 capital budgets similar to the average spending during the 2012 to 2016 period.

In our submission, this is a reasonable solution to the deficiencies in the capital budgeting processes of Hydro One. Alternatively, the Board might allow for the 2015 budget to be increased by inflation. This would result in roughly a $59 million reduction in 2017, and a $130 million reduction in 2018.

[24] Tr. Vol, 6, p.8

Finally, Hydro One argues that "[T]*he issue is not whether ratepayers will bear the cost of doing the work necessary to maintain the system in a proper and safe condition, but rather when ratepayers will bear this cost*."[25] VECC would urge the Board to be wary of such hyperbole. Clearly at some point in time all assets must be replaced or refurbished. The important question is what assets and when? It is oxymoronic to argue that one can purport to know the urgency of the when while at the same time arguing that its predictive modelling cannot be used for capital planning.

In any event, a significant portion of capital spending for 2017 and 2018 is not yet committed as shown below:[26]

Status	2017 ($M)	2018 ($M)
In Scoping	136	405
Budgetary Estimating	244	293
Detailed Estimating	85	69
In Execution	710	459
Total	1,174	1,226

Hydro One clearly has the flexibility to adjust its capital budget to a more modest level more in line with past practice.

Issue #7: Do the proposed capital expenditures include the consideration of factors such as customer preferences, system reliability and asset condition?

In our submission, and with reference to related submissions, under the issues list Hydro One has met the filing requirements of the Board in this matter insofar as these factors have been considered. However, as our submission has pointed out, Hydro One's conclusions on these factors are challenged herein, as is the proposed capital expenditures to be included in revenue requirement.

[25] Argument-in-Chief pg.45
[26] Undertaking J6.3

Issue #8: Are the proposed 2017 and 2018 levels of Common Corporate capital expenditures appropriate?

Table 1: Common Corporate and Other Capital Allocated to Transmission 2012-2018 ($ Millions)

	Historic				Bridge	Test	Test
Description	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**
Information Technology	30.5	22.9	26.8	21.6	33.6	31.4	28.1
Facilities & Real Estate	11.6	7.4	13.7	22.7	22.6	18.4	20.9
Transport, Work, and Service Equipment	14.6	18.8	22.0	22.1	26.1	24.1	25.0
Other (including Distribution Line Loss and CDM)	-14.7	0.0	0.9	0.7	1.2	3.7	5.1
Total	**42.1**	**49.1**	**63.4**	**67.1**	**83.5**	**77.6**	**79.1**

Source B1/T3/S5

Hydro One explains that Common Corporate capital spending levels in the test years are forecast to be higher than historical levels due to: "*(a) higher capital spending on information technology development projects, which aim to improve productivity in Hydro One's operations; (b) increased facility needs for expanding Sustainment, Development and Operations work programs; and (c) incremental capital investments in transport and work equipment, primarily, a new helicopter*."[27]

Given that a large portion of the increase is due to facilities and real estate directly linked to the sustainment capital budget, if the Board reduces the sustainment budget for the purpose of calculating rates, the common corporate costs should be adjusted by a prorated amount. This would require reductions in both OM&A and Capital budgets.

[27] Exhibit B1/T3/S1/pg.5

Issue #9: Are the methodologies used to:

(i) allocate Common Corporate capital expenditures to the transmission business appropriate? and

(ii) to determine the transmission Overhead Capitalization Rate for 2017 and 2018 appropriate?

VECC believes the Board should give consideration to the submissions of Board Staff with respect to these issues. The question posed by Staff is why "IFRS- like" capitalization policies cannot be used under US GAAP accounting. The last study considering the issue was completed by Hydro One in April 2012.[28] The study, done before most Ontario Utilities had moved to IFRS and provides no rationale for the capitalization policy. Rather it is a comparison of Canadian and U.S. utilities capitalization policies. It does not discuss the implications of moving to an IFRS compliant policy and relies heavily on comparison to utilities outside of Ontario.

We are less certain than Staff that customers are worse off under a higher capitalization policy, since theoretically consumers savings in today's rates due to capitalized costs (as opposed to expensed) could be invested. What is not known is the discount rate and what difference lies between that and the Utilities earning on investments.

Nevertheless, the shift to IFRS has been in part a reflection in the accounting community that a stricter notion of what is capital and what is an expense is larger than the issue of GAAP (US or Canadian), or ASPE accounting standards. It is not clear to us why Hydro One should avoid an accounting consensus simply because it has elected US GAAP.

In our submission, the Board should require Hydro One to revisit the issue of capitalization policy by way of a new study. Such a study should go beyond a simple comparison to other jurisdictions, and examine the rationale for capitalization policies, the implications of changing them, and the congruence of Hydro One's policies with those others approved by the Board.

[28] Exhibit I/01/075 Attachment 1

Issue #10: Is the benchmarking evidence adequate/sufficient and does it support the proposed Transmission System Plan and related cost forecasts?

As noted by Board Staff, the two benchmarking studies used by Hydro One have dissimilar results. The CEA results diverge from the Transmission Availability Data System by the fact that the latter looks at the system as a whole, whereas the CEA results look at the southern portion. The difference is in large part a reflection of the redundancy characteristics of the northern and southern parts of the transmission system.

Hydro One faces the difficulty of not only finding comparable utilities (and of that a subset willing to participate), but also by the fact that it system is bifurcated by rural and more urban services. Nonetheless, we are of the view that the metrics that have arisen from the studies (and are spoken to below) are largely relevant, and useful for the purpose of monitoring the Utility's productivity.

In this regard, we would also draw the Board`s attention to the recommendations of the Navigant/First Quartile Consulting Best Practice Recommendations and Implementation Strategy[29]. These include both first steps and long-term implementation goals. In our submission, Hydro One should continue to report on its implementation of these recommendations.

Going forward, we believe that Hydro One should consider refinements to its benchmarking. The most important of these would be the consideration of intra-company comparators. Hydro One operates a large diverse transmission system. Its northern largely radial system has characteristics similar to some transmitters, while its southern operations are more similar to others. A much smaller group are like Hydro One with a combination of the two. It is conceivable to consider at least some of the comparators and metrics on a regional basis. At the very least, we think the concept worthy of exploration and reporting back to the Board.

[29] Exhibit B2/T2/Si/Attachment 1/pgs. 26-27.

C. PRODUCTIVITY IMPROVEMENT AND PERFORMANCE SCORECARD

Issue #11: Has Hydro One taken appropriate steps to identify and quantify productivity improvements in all areas of its transmission operations?

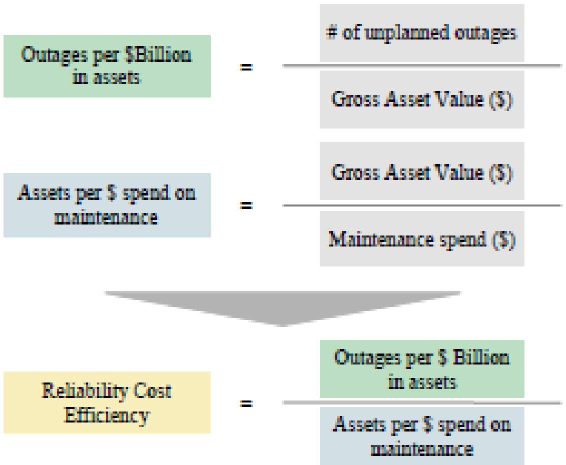
No Submissions

Issue #12: Are the metrics in the proposed scorecard appropriate and do they adequately reflect appropriate outcomes? Do the outcomes adequately reflect customer expectations?

In our submission, Hydro One has made significant efforts to implement a relevant scorecard, meaningful metrics and has taken at least the initial steps toward integrating those metrics into its corporate culture. In our submission, the Board should approve the proposed scorecard with a few adjustments and with the view that there should be meaningful financial consequences for the Company associated with scorecard results.

Hydro One has also explored metrics beyond the standard set used similar to those used by local distribution utilities. Most notable among these "Tier 2" metrics is the RCE or Reliability and Cost Efficiency metrics which links reliability outcomes to maintenance spend. Hydro One is cautious about using this as a meaningful and consequential performance standard . RCE is a metric that relates outages to maintenance spend, normalized by asset values. The principal difficulty associated with its use lies in the possibility that sheer increases in gross asset value may produce a better score without any real improvement in reliability and outages.

However, in VECC's view, this is an innovative metric which has the possibility of showing the efficacy of past investments on capital spending. As well, given Hydro One's proposal to embark on a continuing significant capital program, we believe both the annual and three year rolling average should be included in the scorecard.



The Company can, and should take things further by adopting meaningful unit cost measurements that allow an appraisal of Hydro One's costs measured against historical measurements and other transmission utilities if appropriate.[30]

We are less convinced of Board Staff's arguments that metrics normalized by energy delivered, or OM&A and capital costs make useful comparators. However, we do think that normalizing by the average capacity available could be a useful intra utility metric.

Finally, VECC believes the Board should reconsider the customer delivery point performance standards. These standards are based on 1991-2000 and were approved almost 15 years ago. The current standards based on data over 15 years old are set out below.[31]

Table 1: Customer Delivery Point Performance Standards Based on Load Size

Performance Measure	Customer Delivery Point Performance Standards *(Based on a Delivery Point's Total Average Station Load)*							
	0-15 MW		>15 - 40 MW		>40 - 80 MW		>80 MW	
	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance	Standard (Average Performance)	Minimum Standard of Performance
DP Frequency of Interruptions	**4.1**	**9.0**	**1.1**	**3.5**	**0.5**	**1.5**	**0.3**	**1.0**
DP Interruption Duration	**89**	**360**	**22**	**140**	**11**	**55**	**5**	**25**

[30] Hydro One's objective in the last rates proceeding was to be in the top quartile in terms of unit costs. (Vol. 1 p.95) It is doubtful that it achieved the objective.
[31] Exhibit B1/T1/S3 Also see Tr. Vol. 8 pp41-42

Among the incongruities with the existing standards is the fact that they in essence penalize small connection points more characteristics of the northern radial portion of the transmission system. As such they embed the concept of inferior reliability service to those regions.

As noted above we also believe the Board needs to have Hydro One and the Local Electric Distribution Utilities work together to report outages due to supply issues. Ideally, Hydro One should show the relationship of LDC SAIFI/SAIDI supply related outages to Delivery Point interruptions.

D. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS

Issue #13: Are the proposed spending levels for Sustainment, Development, Operations, and Customer Care OM&A in 2017 and 2018 appropriate, including consideration of factors such as system reliability and asset condition?

Description	2012	2013	2014	Historic 2015	Bridge 2016	Test 2017	Test 2018
Sustainment	204.7	221.0	228.6	233.6	227.5	241.2	238.5
Development	8.4	8.6	7.5	6.1	5.3	4.8	5.0
Operations	54.8	56.7	56.6	59.0	60.0	61.3	62.1
Customer Care	4.4	5.3	5.4	5.1	4.1	4.0	3.9
Common Corporate Costs and Other OM&A	80.7	75.8	37.2	73.9	72.3	49.9	47.5
Taxes Other Than Income Taxes	62.1	21.2	64.1	63.9	62.9	63.6	64.3
Pension Adjustment*	-	-	-	-	-	-11.0	-8.0
B2M LP Adjustment*	-	-	-	-	-	-0.8	-2.1
Total	**415.2**	**388.4**	**399.5**	**441.6**	**432.1**	**413.1**	**411.2**
Capitalization	**106.9**	**109.3**	**124.3**	**116.9**	**122.0**	**133.2**	**134.7**
Gross OM&A, pre-capitalization	**522.1**	**497.7**	**523.8**	**558.5**	**554.1**	**546.3**	**545.9**

Source: Exhibit I/T4/S6

On the face of it, Hydro One has presented a rosy picture of OM&A showing no growth, or even a decline, depending on one's comparator. However, this is a misleading view. When one removes the one-time pension and other adjustments and normalizes for capitalized operating costs, the picture is very different.

We agree with Staff that there are number of incongruities with the OM&A proposal of the Utility. The most glaring is the proposal to increase sustainment costs significantly, while simultaneously proposing a significant increase in the capital budget to replace or refurbish assets.

We also agree with Board Staff that Hydro One has a history of using OM&A to buffer its earnings as shown below.[32]

Actual vs. Allowed - ROE	**2012**	**2013**	**2014**
Property tax rebate	0.0%	0.8%	0.0%
Insurance (flood proceeds)	0.0%	0.0%	0.2%
OM&A	0.3%	0.2%	0.6%
Depreciation	0.5%	0.7%	0.9%
In-service	0.3%	0.2%	0.3%
Other - Weather	1.9%	2.4%	1.8%
Total Over Earn	**2.99%**	**4.29%**	**3.76%**

Board Staff argues for a reduction in OM&A to compensate for consistent underspending, for excessive corporate management and communications costs and for failing to maintain or improve overall benchmarked compensation. The suggested reductions are $54 million in 2017 and $55 million in 2018.

It is clear that from a management perspective Hydro One is moving in a new, and more expensive, direction. In addition to the issuance of public shares, a new Governance Agreement is being implemented which attempts to put more distance between Hydro One and the Government of Ontario[33].

This change has, in turn, had an impact on compensation. The first point to consider is that the Mercer Study did not impute a value of the lump sum share payments to the

[32] Undertaking J12.3
[33] Exhibit A/T5/S1/pg.3

PWU and Society employees[34]. The second is that Hydro One has seen its executive and board management costs go significantly up as part of this strategic change.[35]

The type of ownership, be it public or private, of Hydro One should be a no consequence in setting rates. Management costs are increasing in this application. We have no evidence that the prior management was any less able than their replacements. The evidence is that these costs are driven by the partial privatization of the Utility. Such actions may be good for increasing shareholder value, but they do not provide value to ratepayers and therefore they should be disallowed.

This issue was most notably explored by Chair Quesnelle, in his questions to Hydro One expert witness Mr. Soare about the value proposition of having someone with private sector related experience operating a publicly traded company[36]:

> MR. SOARÉ: Well, I am just making the point that in our experience, people -- boards of directors who are in charge of especially mid to larger cap companies, ideally if they are looking for a new CEO because they have to -- the old one is gone or whatever, they would want to have the new person with public company experience.
>
> If they have never operated in a public company experience, but they are otherwise solid executives, that's good. But ideally, you'd want to have that same talent, but hopefully with the knowledge of how to deal with investor relations, how to deal with investment banks, how to deal with whatever. And that you only get if you have dealt with publicly traded.
>
> I am just merely pointing out that the in my opinion, the capacity should be as high in either case. But ideally, in a publicly traded, environment you would have somebody at the very top someone understands the publicly traded environment.

This additional compensation cost factor associated with the transition to an investor-owned company was driven home in Mr. Soare's re-examination by Hydro One counsel:

> MR. NETTLETON: Thank you, Mr. Chairman.
>
> Mr. Soaré, I have only one area of redirect, and it really follows from the last question that the chair, Mr. Quesnelle, asked you, and it was regarding the publicly traded aspect of your study, of your peer group, if

[34] Undertaking J10.3
[35] See for example Undertaking J12.5
[36] Tr. Vol.8, p.158

> you will, and the aspect that you have captured in your peer group, and I think the question that arises in redirect is this: Why didn't you include any non-public or Crown corporations in your peer group, such as Hydro Quebec?
>
> MR. SOARÉ: The pay practices at these other Crowns are interesting, but when you are trying to attract the talent that you need to run, in this case a $25 billion enterprise, the board is going to use the talent market that is better represented by the companies that we put forward.
>
> And the market price for running publicly traded $20 billion companies is as presented in our report, and the problem with other data points like the one you point out is some of those companies are enormous, such as Quebec Hydro, but they don't pay what publicly traded companies pay, and I can't comment on the nature of the person running Quebec Hydro, but if a board -- if a company is offering compensation that is a small fraction of what the market commands, in our experience you are not going to attract the full range of talent that you would when you offer market competitive pay.
>
> So the way I think about it, the company that -- in that case a Crown corp. that offers 10 percent of what the market pay is might get lucky and get a pretty good manager, but they excluded from the possibility of attracting people who have experience running $50 billion companies whether they are public or private. They don't have -- they never gave themselves a chance, because they didn't have a price point that is reflective of the talent that runs major corporations.
>
> So I think that the talent pool is different and the price point is not relevant for running a 20-plus billion-dollar company. [37]

While the answer of Hydro One's expert pertains to the CEO, it is likely instructive for differences in compensation between Crown corporations and publicly traded corporations like Hydro One. It is clear that the new "Hydro One" has repurposed itself to be "commercially oriented"[38] and that believes it has "a mandate to make the business more efficient"[39]in accordance with the goals set out in Exhibit A, Tab 3, Schedule 1 page 4 Table 1. It is less clear whether the new look costs more for ratepayers.

[37] Tr. Vol. 8. P.160
[38] Tr. Vol 1,p.21
[39] Tr. Vol 2. P.56

The issue that needs to be addressed is not whether the new executive or board members of Hydro One are talented and are “worth the money.” The shareholder is charged with organizing the company in an efficient fashion. Rather, the question is what extra value is provided to ratepayers by this extraordinary increase in management costs? We would argue that the case has not been made that the goals referenced in Table 1 above are only achievable for ratepayers with higher costs. Certainly shareholder value might be increased by expending more on the idea that management with a private sector focus can provide better shareholder value. We have nothing against increased shareholder value so long as it is not extracted by leveraging the monopolistic facets of the Utility. And we see no compelling evidence which would lead us to believe that the increase in executive and board management costs proposed to be included in the revenue requirement are justified.

For these reasons we support Board Staff proposed reductions of $4.5 million in 2017 and $5.7million in 2018 for excessive corporate management and communications costs.

Issue #14: Do the proposed OM&A expenditures include the consideration of factors such as system reliability, asset condition and customer preferences?

VECC has no submissions on this issue as it pertains to OM&A.

Issue #15: Are the proposed spending levels for Common Corporate Services and Other O&M in 2017 and 2018 appropriate?

We have made our submissions under issue # 8 above

Issue # 16: Are the 2017 and 2018 human resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate?

VECC explored two other problems with the compensation of Hydro One (and similar utility compensations studies in general). The first is with respect to circularity and the self-comparison which is part of typical compensation studies. The second issue is the relationship between executive and management and other compensation (so called horizontal compensation studies) VECC explored both of these issues with Hydro One's compensation expert from Wilis Towers & Watson.[40]

Hydro One has provided typical comparator compensation evidence. This type of study is done, not just by regulated companies, but also by other firms to set (or justify) compensation. The weakness of these studies is that by comparing against similar entities, they are prone to replicating each other's results. Hydro One is aligned at or slightly above the median market of similar utilities market[41]. That is, Hydro One employees have similar compensation to other monopolies. We would not be surprised, of course, to find many of these utilities appearing before their regulators using similar studies to show how they are earning slightly less than Hydro One. And on it goes.

However, times are changing. All companies, but especially public and monopolies are being questioned as to their compensation levels, especially their executive compensation. The Government of Ontario has only recently (and somewhat hesitantly) lifted a freeze on public sector executive compensation. The OEB has instituted public meetings for a number of distribution companies proposed rate increases. It has heard from ratepayers their frustration with excessive compensation.

VECC represents customers who over the past decades have seen almost no increase in their real wages whereas monopoly utilities like Hydro One have continued to see wages that exceed inflation, and without the necessary productivity growth to offset

[40] Transcript Vol.9 pgs. 142-145
[41] Exhibit C1/T4/S1/pg.18

those costs. The results are increasingly unaffordable energy costs for low and middle income families.

While executive salaries are a small part of the overall revenue requirement their recovery in rates sets an example both within the utility to its other employees and outside to its customers. Within the Company, keeping unionized labour costs in check is a task which starts by the example of the Utility's executive.

Horizontal compensations studies are being done by progressive corporations who are sensitive to public perception about the growing compensation gap between senior employees with public and monopoly companies and the majority of other workers. The gap between the compensation of the lineman, a customer service representative and the executives of the company sends an important for the message not just about the fairness of the Utility, but also its commitment to keeping labour costs in check.

In our submission, the Board needs to be provided evidence on the evolution of wages, both generally, and in the broader sectors of the economy as compared to the increase in the category costs of the Utility[42]. As we have pointed out in this proceeding, such data is readily available from Statistics Canada both for the overall economy but also by economic sector (including we note – utilities). Requiring regulated utilities to "look outside the box" rather than a similarity well compensated employees would be one step toward better understanding utility cost escalation.

Issue #17: Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

See Issue #16

Issue #18: Are the methodologies used to allocate Common Corporate Costs and Other OM&A costs to the transmission business for 2017 and 2018 appropriate?

VECC has no submissions under this issue.

[42] i.e. Executive, management, collective bargain and non-unionized

Issue #19: Are the amounts proposed to be included in the 2017 and 2018 revenue requirements for income taxes appropriate?

The effect of the arrangements associated with the departure tax is the only significant issue to be resolved by the Board. Hydro One was assessed a $2.6 billion departure tax by the Government of Ontario, which then proceeded to inject an equal amount of new equity into the Corporation. The transaction gives rise to a deferred tax asset to be used to reduce future taxes. The allocated portion to the transmission business is around $1.5 billion. None of future tax implications of this transaction are incorporated into the revenue requirement on the basis of the standalone rate making principle.

The effect of this will be, all other things being equal, that Hydro One's actual taxes paid will be lower than the tax component embedded in rates and the Utility will over earn with respect to the regulatory ordained cost of capital. This overearning would normally be shared by the (now public and private) shareholders of Hydro One via dividends or through the valuation of shares. However, Hydro One issued new shares in return for the $2.6 billion payment and in the process diluted the value of existing shares. Conceptually under Hydro One's proposal shareholders will receive the equivalent value of the pre-injection shares through these future overearnings[43]. If the Board were to impute the value of the tax shield that arises from this transaction, it would thereby devalue the shares transferring that value to ratepayers[44].

We have had the benefit of reviewing a draft of the SEC submissions on this issue herein, and we realize that the issue of the recognition or allocation of the benefits of the transaction is not a straight forward proposition, nor one that can be established with certainty based on precedent. As a representative of low income consumers, VECC would prefer, of course, a result that sees rate decline by the value of the tax shield. If the decision is made that Hydro One's proposed treatment is in accord with the making

[43] The transaction occurred prior to public issuance – see Undertaking J11.11

[44] In our understanding this is in effect to say the the same as what is stated in the corrected transcript response of undertaking J1.3

of just and reasonable rates, then it is imperative that the stand-alone principle be strictly applied to revenue requirement to insure that the effects of the transition to an investor owned company unrelated to the delivery of service are insulated from ratepayer's pocket books. As we have noted, an earnings sharing approach would provide some comfort that ratepayers are not taking a back seat to investors on this score (with suitable adjustments in the event of an approval of the Hydro One recommended treatment to isolate the revenue arising from the treatment from the balance that may be subject to earnings sharing) .

Issue #20: Is Hydro One's proposed depreciation expense for 2017 and 2018 appropriate?

VECC has no submission on this issue.

E. RATE BASE & COST OF CAPITAL

Issue #2: Are the amounts proposed for rate base and capital structure in 2017 and 2018 reasonable?

VECC has no submissions with respect to the 2017 and 2018 capital structure. Our rate base submissions are made with respect to issues #5 and #6.

Issue #22: Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

Hydro One Transmission's net cash working capital requirement for the 2017 test year is based on 3.4% in 2017 and 3.7% in 2018 of OM&A expenses. This is in contrast to prior years as shown below[45]:

Table 13: Summary of Historical Working Capital Requirements

	2010 Study		2012 Study		2014 Study	
Test Year	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
WCR as a % of OM&A	**1.57%**	**1.12%**	**2.80%**	**2.58%**	**2.81%**	**2.27%**

When queried about this increase, Hydro One responded that the primary factor of this increase is the inclusion of a significant pre-payment of utility income tax in the first half of the year which was not captured in the prior study. The pre-payment of utility income tax are based on predictions of net income. The 2018 increase over 2017 was attributed to higher interest expenses as a result of the increased long term debt being borrowed in 2018[46]

In fact there are a number of differences in the prior studies and the one filed in this application. Those differences were identified by London Property Management Association (LPMA) at Exhibit I, Tab 4, Schedule 29 and include:

i) pensions: (45.68) to 28.18;
ii) group life insurance: 6.56 to 0.86;
iii) group health and dental -ASO; 30.83 to 56.48;
iv) group health and dental - claims: 1.89 to 10.9;
v) payroll - basic: 18.50 to 26.70;
vi) payroll - construction: 18.50 to 11.49;
vii) payroll - management: (0.8) to 25.91;
viii) payroll - supervisor pensions: (15.13) to 25.91;
ix) payroll withholdings - management: 7.22 to 40.29; and
x) payroll withholdings - supervisor pensions: (8.50) to 40.29.

[45] EB-2014-0140 Exhibit I-10-16 Attachment 1 this table is the same as that found at Table 14 of Exhibit D1/T1/S4 Attachment 1/pg. 16 but in addition includes the 2010 study.
[46] Exhibit I/Tab 1/Schedule 141

LPMA asked that Hydro One explain these changes and was in turn told: *"A detailed review requested in this interrogatory is unreasonable based on the immateriality of 23 the impact to revenue requirement, relative to effort involved to conduct the review within the time allowed*. A similar response was given to other inquiries around the adjustment with respect to the debt instruments[47]

The refusal of Hydro One to explain the significant changes in its lead-lag study results in it not meeting its burden of proof in this application. For this reason it is our submission Hydro One should be ordered to utilize the last approved study figure of 2.27% for both 2017 and 2018.

Issue #23: Are the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

VECC has no submissions with respect to this issue

Issue #24: Is the forecast of long term debt for 2017 and 2018 appropriate?

VECC has no submissions under this issue.

F. LOAD REVENUE FORECAST

Issue #25: Is the load forecast methodology and the resulting load forecast appropriate?

Hydro One Networks' transmission load forecast is developed using three different models: two econometric models (one a monthly model and the second an annual model) and an end use model[48]. Based on these models forecast growth rates are developed and applied to the weather corrected load for the base year (2015)[49].

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[47] See for example Exhibit I, Tab 4, Schedule 31.
[48] Exhibit E1/T3/S1, page 9, pages 14-19 and Appendices A, B & C.
[49] Exhibit I/T4/S43 a)

Weather correction is based on average weather conditions over the last 31 years[50]. For CDM and embedded generation, the (post 2006) load impacts are added back to historical use value for modelling purposes and then subtracted from the forecast load for the test years[51].

In principle VECC has no concerns about Hydro One Networks' general 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 number of specific concerns with the way this approach has been applied in the current Application. These concerns are described in the following sections.

a) Treatment of Demand Response

In its EB-2006-0501 Decision[52] the Board agreed that impact of Demand Response (DR) Programs should not be reflected in the Hydro One Networks' transmission load forecast since the load forecast is based on normal weather and DR programs are most effective in extreme weather conditions. For purposes of its load forecast models, Hydro One has only added back the historical impacts of energy efficiency programs and codes & standards and, then for 2017 and 2018, reduced the resulting forecasts by the anticipated impact of energy efficiency programs and codes & standards in those years[53]. Hydro One Networks also notes that the impact of DR programs was neither added back into 2015 actuals used as the base year for the forecast nor subtracted from the resulting forecast. This approach gives rise to two issues.

First, the models (both econometric and end-use) developed and used by Hydro One Networks would be different and hence yield different forecast growth rates through to 2018 if the impact of DR programs had been added back into the actual values used to establish the models. This means that the forecast (prior to adjustments for CDM and

[50] Exhibit E1/T3/S1, page 11
[51] Exhibit E1/T3/S1, pages 9-10 and 19-22
[52] Page 91
[53] Transcript Volume 12, pages 139-140

codes & standards) would have been different giving rise to a different final load forecast.

Second, as Hydro One Networks acknowledges, since the load forecast uses actual (weather corrected) 2015 load as the basis for the forecast, the DR program impact reflected in the 2015 actual peak is also reflected in the 2017-2018 load forecast[54]. Hydro One Networks appears to suggest that this is appropriate since, in the 2013 LTEP, there is no change in the peak impact from DR sources between 2015 and 2018[55].

It is VECC's submission that this totally misses the point of the Board's 2006 Decision. Hydro One Networks claims that since the impact of DR is constant its treatment is the same as if DR had been added back in and then subtracted[56]. However, point of the 2006 Decision was that the impact of DR programs should not be reflected in the load forecast at all. Furthermore, due to the compounding effect of applying growth rates to the 2015 actual load, ignoring the impacts of DR in 2015 does note mathematically yield the same result as adding the impacts back in for 2015 and then subtracting the same impact out in 2017 and 2018.

In VECC's view conformance with the Board's 2006 Decision requires that: i) Hydro One Networks' load forecast models be developed using actual (weather-corrected) load that have been adjusted (i.e. increased) to account for the impact of energy efficiency, codes & standards and DR programs; ii) the forecast growth rates be applied to a 2015 base year that has been adjusted (increased) to reflect the impact of DR programs as well as energy efficient initiatives and codes & standards and iii) the final adjustments made to the resulting forecast reflect only the impact of energy efficiency programs and codes & standards.

Given the current state of the record, VECC acknowledges that the corrections required under point (i) cannot be affected for purposes of setting the 2017 and 2018 transmission rates. However, Hydro One Networks has indicated[57] that the 2015 peak

[54] TCJ1.7 – VECC 43 a)
[55] TCJ1.7 – VECC 43 a) and VECC 45 a)
[56] TCJ1.7 – VECC 45 a)
[57] Exhibit I/T12/S29 a)

impact of DR programs was 1,072 MW and VECC submits that, consistent with point (ii), the actual 2015 pre-CDM weather corrected peak demand used as the starting point for determining the 2017 and 2018 forecast should be increased by this amount. Furthermore, VECC submits that the Board should direct Hydro One Networks in the next transmission rate application, to revisit the treatment of DR programs in developing its load forecasting models (per point (i)) so as to align it with the expectations of Board as set out in the EB-2006-0501.

b) Historic CDM values used for modelling purposes

The annual econometric model was developed using actual data up to 2014 while the monthly econometric model used actual data up to February 2016[58]. The "actual" values for the impact of energy efficiency programs and codes & standards were based on values taken from the OPA's 2011 IPSP for the period up to 2012 and then on values taken from the OPA's 2013 LTEP for the years thereafter[59].

Hydro One Networks has acknowledged that the values used for 2013 and 2014 were OPA forecast values but claims that the IESO has assumed that actual savings in those years are equivalent to the LTEP forecast savings and that this approach was used in order to be consistent with the IESO[60].

However, it is VECC's submission that the IESO has not assumed that the 2013 and 2014 actual energy efficiency savings are the same as those forecast by the OPA. A careful reading of the references provided by Hydro One Networks in response to VECC 27 b) indicates that the IESO in its assessments of 2013 and 2014 actuals versus forecast values <u>only</u> assumed that the values for codes & standards were the same as forecast as seen by the following excerpt from the 2014 Report[61].

> Savings from conservation programs are between 2006 and 2014 including persistence. Savings from codes and standards are between 2006 and 2013 and assume the same as forecast in LTEP. Forecast new 2014 savings from codes and standards are not included. Evaluation of savings from codes and standards is under way.

[58] Transcript Volume 12, page 138
[59] Exhibit I/T12/S27 b)
[60] Exhibit I/T27/S27 c) and Transcript Volume 12, pages 140-142 and page 151
[61] Exhibit K12.6, page 14

A similar statement indicating that the assumption actual values were equal to forecast values applied only to codes & standards can also be found in the 2013 Report referenced in VECC 27 b). Indeed, during cross examination[62], Hydro One Networks agreed that the IESO did not indicate it was assuming actual savings from energy efficiency were the same as forecast.

Also, an examination of the 2013 and 2014 Reports indicates that total actual energy savings in both years is different than that forecast by the OPA[63]. In VECC's submission, if the actual energy savings are different than forecast it is reasonable to assume that the associated actual peak demand savings will also vary from those forecast by the OPA.

VECC also notes that in response to undertakings provided during the oral proceeding Hydro One Networks filed the IESO's Ontario Planning Outlook (September 2016) which provides the latest IESO energy savings figure for conservation for 2014 (11.3 TWh), again different from that forecast by the OPA in the 2013 LTEP. Indeed, this same document provides an updated history of conservation savings back to 2006[64] and the values for 2011 and 2012 are different from those used by the OPA in its 2013 LTEP[65]. Again, VECC submits that if the historical energy conservation values have changed it is reasonable to assume that the associated actual peak demand savings have also changed.

Similarly, VECC notes that the actual CDM energy savings for 2015 as reported in the new materials Hydro One Networks filed, after the oral proceeding, as part of the undertaking responses, are higher than those forecast in the 2013 LTEP[66]. Again, if the energy savings are higher than forecast then it is reasonable to assume that the associated demand savings will also be higher (thus increasing the base to which the forecast growth rates are to be applied).

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[62] Transcript Volume 12, pages 143-144
[63] In both cases see Slide 7 of the 2013 and 214 IESO Reports referenced in VECC 27 b)
[64] J12.6, Attachment 1, Data Tables, page 7
[65] LTEP 2013 – Module 2, page 6 (http://powerauthority.on.ca/sites/default/files/planning/LTEP-2013-Module-2-Conservation.pdf)
[66] J12.6, Attachment 1, Data Tables, page 21 (2015 value is 12.8 TWh vs. 10.9 TWh in the 2013 LTEP per Module 2 in previous reference

Overall, it is VECC's submission that the actual CDM values used by Hydro One Networks in the development of its load forecast models are both incorrect (in the case of the 2013, 2014 and 2015 values where forecast values were erroneously used in lieu of actual values) and/or require updating (in the case of the 2011 and 2012 values).

During the oral hearing[67], Hydro One Networks suggested that, within certain limits, no matter what CDM adjustment was assumed the final forecast would be robust in respect to those assumptions. However, revising the actual values for CDM would change the energy values used in the development and formulation of Hydro One Networks' load forecast models[68] including the effects ascribed to other explanatory variables. As a result, the overall forecasts for 2017 and 2018 would be different after removing the effects of CDM.

VECC submits that the overall effects are unknown and are not necessarily negligible as suggested by Hydro One Networks. However, given the current state of the record, VECC accepts that it is likely necessary for the Board to adopt the forecast models and resulting (pre-CDM) growth rates developed by Hydro One Networks for purposes of setting the 2017 and 2018 transmission rates. However, VECC submits that the Board should direct Hydro One Networks, in its next transmission rate application, to update its load forecast models to reflect the best available history of actual CDM results.

c) Historic and forecast energy prices

The formulation of Hydro One Networks' load forecast models requires historical data on both electricity prices as well as the prices for other energy forms[69] and, similarly the development of the load forecast for 2017 and 2018 requires forecast values for the same parameters.

The stated basis for both the actual (2006-2015) and forecast prices used has changed during the course of the proceeding and is still not clear. In the initial Application[70], Hydro One Networks indicated that the historical prices came from Statistics Canada and the forecasts were prepared by Hydro One Networks. Then, in response to the

[67] Transcript Volume 12, pages 150-153
[68] Exhibit E1/T3/S1, Appendices A, B and C
[69] Exhibit E1/T3/S1, Appendix B, pages 30-35
[70] Exhibit E1/T3/S1, Appendix B, pages 30, 32 and 34.

information requests, it was noted that the forecast residential and commercial electricity prices were based on the 2013 LTEP while industrial price forecast was based from the NEB[71]. Subsequently, in response to undertakings[72] made during the oral proceeding, it was indicated that for the period 2012-2015 the end use electricity prices (include transmission and distribution) were based prepared by Hydro One based on calculations of year over year changes from 2011 in the commodity cost of electricity.

In VECC's view both the historical and forecast electricity price used are problematic. The assumption that for 2012-2015 the historic (pre-2012) relationship between commodity prices and end-use prices will continue is unsupportable given that distribution and transmission rates are set on totally different basis than the commodity price of electricity. Furthermore, in terms of the forecast for post 2015 prices it appears that Hydro One Networks' is continuing to use the residential and commercial price forecast in the 2013 LTEP, which is now considerably dated.

Again, VECC accepts that it is likely necessary that (in lieu of any alternative forecast) the Board adopt Hydro One Networks' electricity price forecast for purposes of forecasting load in 2017 and 2018.. However, VECC submits that the Board should direct Hydro One Networks that if it wants to continue to use load forecast models that incorporate actual and forecast electricity prices than the actual and forecast values should be derived on a consistent basis and using the most up-to-date information available.

d) Weather Normalization

In its Application Hydro One Networks provided historical information suggesting that any past trend in temperature had been "broken" since 2014[73] and therefore use of a 31-year average was more appropriate for weather normalization. In contrast, the update provided during the Technical Conference[74], suggests that a trend may still exist (i.e. the additional data up to September 2016 shows an increase in the maximum

[71] Exhibit I/T12/S33
[72] J12.8
[73] Exhibit E1/T3/S1, page 13
[74] TCJ1.14

temperature in the last few months). However, using a 20-year trend to establish the charge determinants would only increase the 2017 and 2018 forecast load by 0.03% and 0.07% respectively[75]. Given the small difference VECC submits that it is reasonable to use Hydro One Networks' load forecast based on a 31-year average for purposes of setting 2017 and 2018 rates[76].

At the same time, VECC submits that given the updated information provided at the Technical Conference, Hydro One Networks should be directed to include in its next rate application the results of using a 20-year trend for purposes of weather normalization as well as its proposed approach to weather normalization..

Issue #26: Have the impacts of conservation and demand management initiatives been suitably reflected in the forecast?

Hydro One Networks' forecast CDM impacts on peak demand for 2017 and 2018 are based on the estimated cumulative impact of energy efficiency programs from 2006 through to the respective test years as set out in the 2013 LTEP[77].

VECC notes that the forecast of energy efficiency savings underpinning these demand reductions have been superseded by more recent updates from the IESO[78]. However, the demand impacts associated with the revised energy savings forecast are not on the record. Furthermore, in VECC's submission, it would be inappropriate to update the 2017 and 2018 forecast savings demand without also updating the historical (2011-2015) values used to develop the load forecast (prior to CDM impacts) as discussed in section b) of VECC submissions regarding Issue #25.

As result, VECC submits that the Board should accept the 2017 and 2018 impacts of CDM as filed for purposes of setting 2017 and 2018 transmission rates but direct the company to ensure the most recent CDM forecasts are utilized in its next rate application.

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[75] Exhibit I/T4/S42 b)
[76] Subject to the adjustment discussed in part (a) above
[77] Exhibit E1/T3/S1, pages 8-9 and Exhibit I/T12/S27 b)
[78] J12.6, Attachment 1, Data Tables, page 21

Issue #27: Are Other Revenue (including export revenue) forecasts appropriate?

VECC notes that Issue #31 explicitly addresses the matter of export service revenues and, therefore, the submissions in this section will be limited to Other Revenues – excluding export revenue.

Hydro One Networks' is forecasting other/external revenues from sources other than export service of $28.2 M in 2017 and $28.5 M in 2018[79]. Historically sources for the other/external revenues include Secondary Land Use, Station Maintenance, Engineering and Construction Services, and Other (e.g. telecom services, revenue from special planning studies, customer shortfall payments and the lease of idle transmission lines) [80].

VECC notes that Hydro One Networks external/other revenue forecasts for 2017 and 2018 are lower than historic 2012-2015 levels. Hydro One Networks has provided explanations for the forecast reductions:

- Secondary Land Use revenues were higher in the historic years due to one-time sales and easement transactions for major projects of which none are currently forecasted for 2017 or 2018[81].
- Station Maintenance is lower due to a drop in work on OPG's Pickering and Darlington station. In addition maintenance work for Bruce Power decreased in 2015 and is expected to continue to decline in the future[82].
- Historically, Engineering and Construction revenue was derived from upgrading revenue meters to meter IESO requirements and this work was completed in 2015[83].

However, VECC notes Hydro One Networks' past two[84] Applications have both included significant forecast reductions in external/other revenues from historic levels attributable

[79] Exhibit E1/T2/S1, page 2
[80] Exhibit E1,T2/S1, page 5
[81] Exhibit I/T1/S142 a)
[82] Exhibit I/T1/S142 b)
[83] Exhibit E1/T2/S1, page 5
[84] EB-2012-0031, Exhibit E1/T2/S1, page 2 and EB-2014-0140, Exhibit E1/T2/S1, page 2

to lower revenues from both Secondary Land Use and Station Maintenance which, in both cases, have failed to materialize[85].

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 External Station Maintenance, E&CS and Other External Revenues. 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 2017 and 2018 are acceptable for purposes of setting the transmission rates in these years provided the Board approves the continuation of these regulatory accounts.

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 2017 and 2018 should be set at $48.4 M which represents the average annual actual revenues for the most recent three years (2013-2015).

G. DEFERRAL/VARIANCE ACCOUNTS

Issue #28: Are the proposed amounts, disposition and continuance of Hydro One's existing deferral and variance accounts appropriate?

In its EB-2014-0140 Decision the Board approved the creation/continuation of 13 regulatory accounts[86]. Hydro One Networks is proposing the continuation of all of these accounts except for the LDC CDM and Demand Response Variance Account[87].

As part of this Application Hydro One Networks is also proposing to dispose of the forecast December 31, 2016 balances associated with nine of these accounts totalling

[85] This can been seen by comparing the forecast values as referenced above with the actual revenues for 2013-2015 as set out in Exhibit E1/T2/S1, page 2
[86] Exhibit F1/T1/S1, pages 2-3
[87] Exhibit F1/T1/S2, page 1 and Exhibit I/T12/S28 i)

$95.6 M[88] which is to be divided equally between 2017 and 2018[89]. The four regulatory accounts for which Hydro One Networks is not proposing disposition are[90]:

- East-West Tie Deferral ($1.1 M forecast as of December 2016)
- SECTR Deferral ($0.6 M forecast as of December 2016)
- North West Bulk Transmission Deferral ($1.5 M forecast as of December 2016[91])
- In-Service Capital Additions (No entries will be made until the actual 2016 capital additions are known[92])

a) Regulatory Asset Account Balances

VECC notes that Hydro One Networks is seeking approval of the regulatory account balances as of December 31, 2015 (130.7 M)[93]. During the interrogatory and technical conference processes VECC requested additional information on the 2014-2015 annual transactions associated with each account[94] as well as details regarding the determination of the annual additions to the LDC CDM and Demand Response Variance Account[95]. With respect to this later account, VECC notes that the response to TCJ1.7 indicates a minor adjustment is required to the verified MW savings used in the calculation of the additions related to 2013 (reported in 2014).

Furthermore, with respect to the LDC CDM and Demand Response Variance Account, VECC accepts that the calculation of the amounts to be recorded for each year (2013 and 2014) could not be calculated and posted to the account until after the verified results were available from the OPA/IESO the following year. However, VECC notes that interest on the accounts is only calculated from year in which the values are "posted" (For example, the impact for 2013 CDM and Demand Response was not

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[88] The 2016 balances include Board approved dispositions for 2016 and forecast interest improvement for 2016 but do not include any 2016 transactions.
[89] Exhibit F2/T1/S2, page 1
[90] Exhibit F1/T1/S1, pages 10-13
[91] While Table 2 (Exhibit F1/T1/S1, page 3) shows a balance of zero the discussion on page 10 indicates a balance oof $1.5 M
[92] Exhibit F1/T1/S1, page 13
[93] Exhibit A/T2/S1, page 3
[94] Exhibit I/T12/S35
[95] Exhibit I/T12/S36 and TCJ1.7, VECC-49. Note the 2014 and 2015 transactions are related to CDM activities in 2013 and 2014 respectively.

posted until 2014 and interest was only calculated starting in 2014[96]). VECC is of the view that the interest calculation for this account should recognize that the revenue impacts actually occur one year before the “posting” is made and submits that Board should direct Hydro One Networks to calculate interest on the balances starting in the year the impacts actually occurred.

b) Proposed Regulatory Account Dispositions

Subject to any revisions required as a result of the preceding comments, VECC has no issues with Hydro One Networks proposal regarding the disposition of its regulatory account balances.

c) Continuance of Existing Accounts

VECC supports Hydro One Networks’ proposal to continue with existing deferral and variance accounts with the exception of the LRAMVA account.

Issue #29: Are the proposed new deferral and variance accounts appropriate?

Hydro One Networks is not proposing any new deferral or variance accounts and VECC takes no issue with this position.

H. COST ALLOCATION

<u>Issue #30: Is the transmission cost allocation proposed by Hydro One appropriate?</u>

Hydro One Networks’ Cost Allocation methodology is the generally the same as that accepted by the OEB in its EB-2008-0272 Decision[97] and used in subsequent applications, including the EB-2014-0140 Settlement Agreement dealing with the currently approved rates. The one exception is that Hydro One Networks is proposing to expand the Transmission Connection functional category to include Whole Revenue Metering Assets that are currently captured in a separate Wholesale Meter functional

[96] Exhibit I/T12/S35
[97] See EB-2008-0272 Decision, page 63

category[98]. The rationale for eliminating the Wholesale Meter functional category is that the number of Whole Revenue Metering ("WRM") points whose assets make up this functional category have decreased significantly from 1,700 in 2002 when the market opened to 52 as of the end of 2015[99]. Furthermore, the number of installations will continue to decrease as the seal periods on the associated equipment expire and customers are required to make other arrangements.

It is Hydro One Networks' position that the small costs associated with the remaining installations no longer justify maintaining a separate functional category. Rather these assets, which are located in transformer stations, will be included in the Transformation Connection functional category[100]. However, Hydro One Networks proposes to maintain the current Wholesale Meter Service fee ($7,900 / year) with the revenues used to offset the total costs assigned to the Transformation Connection functional category[101].

During the interrogatory phase 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[102]. In VECC's view, Hydro One Networks has adequately explained the changes that have occurred as between the two applications.

With regard to the proposed change in the treatment of the Wholesale Meter functional category, VECC submits that incorporating the function into the Transmission Connection function, while maintaining the Wholesale Meter Service fee (and using the revenues to offset the costs) is reasonable. As Hydro One notes the costs involved are small and, indeed, all of the current meter installations are connected to the same customer[103].

VECC notes that the proposed Wholesale Meter Service fee ($7,900 / annum) is not based on an estimate of the 2017 cost of providing the service but rather based on the

[98] Exhibit G1/T2/S1, page 9
[99] Exhibit G1/T2/S1, page 10
[100] Exhibit G1/T2/S1, page 10
[101] Exhibit H1/T3/S1,page 3
[102] Exhibit I/T12/S39 & S40
[103] Exhibit I/T12/S37 a)

currently approved fee[104]. While, ideally the fee should be cost-based, VECC submits that this approach is reasonable given that the cost-based fee has been $7,900 since 2012[105].

I. EXPORT TRANSMISSION SERVICE RATES

Issue #31: Is the Export Transmission Rate of $1.85 and the resulting ETS revenues appropriate?

Hydro One Networks proposes to maintain the Export Transmission Service Rate (ETSR) at it currently approved level of $1.85 / MWh[106]. Forecast export volumes for 2017 (21.18 TWh) and 2018 (21.65 TWh) are calculated based on a three year rolling average of historical export volumes. The resulting forecast export revenues for 2017 and 2018 are $39.17 M and $40.05 M respectively[107].

The currently approved $1.85 / MWh ETSR is the result of a settlement agreement arising from Hydro One Networks 2015/16 Transmission Rate Application (EB-2014-0140). It is important to note that while, as part of its earlier EB-2014-0140 Application, Hydro One Networks submitted a cost allocation study to support the ETSR proposed at that time, this study was explicitly not accepted[108] by the parties to the subsequent settlement agreement nor was it reviewed/approved by the Board. As a result, the EB-2014.-0140 settlement agreement does not provide a way forward as to how the ETSR should be updated/set in the future.

VECC notes that in the current proceeding no evidence has been submitted regarding how an appropriate ETSR would be established. Based on this and the fact that the proposed 2018 Network Service rate is virtually the same as that approved for 2016 ($3.68 versus $3.66/kW/month[109]) VECC submits that the Board should accept Hydro One Networks' proposal to maintain the ETSR at $1.85/kWh for 2017 and 2018.

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[104] Exhibit TCJ1.7 – VECC 50
[105] Board Decision re UTR – EB-2011-0268
[106] Exhibit H1/T4/S1, page 2
[107] Exhibit I/T11/S39 a) & b)
[108] Settlement Agreement, page 25
[109] Exhibit H2/T2/S1, Attachments 1 & 2

VECC also notes that Hydro One Networks is proposing[110] to continue the current regulatory account that track Excess Export Service Revenue and supports the continuation of this account. VECC submits that in conjunction with this proposal it is reasonable for the Board to accept Hydro One Networks' forecast export service volumes for 2017 and 2018 along with the resulting export service revenue forecasts.

Reasonably Incurred Costs

VECC submits that its participation in this proceeding has been focused and responsible. Accordingly, VECC requests an award of costs in the amount of 100% of its reasonably-incurred fees and disbursements.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

[110] Exhibit F1/T1/S2, page 2