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Ontario Energy Board
2300 Yonge Street
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Toronto, Ontario
M4P 1E4

Attn: Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: EB-2018-0218 – Hydro One SSM – SEC Final Argument

We are counsel to the School Energy Coalition ("SEC"). Pursuant to Procedural Order No. 5, this is SEC's Final Argument on the application by Hydro One Sault St. Marie ("SSM") for approval of rates for 2019 and the rate adjustment mechanism through the deferred rebasing period.

Revenue Cap Index

Hydro One SSM has proposed a Revenue Cap Index ("RCI") which would provide an annual adjustment to its revenue requirement based on a proposed inflation, productivity and stretch factor. SEC submits that the RCI approach is consistent with the Board's expectations in the EB-2016-0050 MAADs decision. With that said, SEC makes the following submissions related to the specific elements of the proposed RCI.

Productivity and Stretch Factor. SEC is mindful of the Board's direction in Procedural Order No. 5 that "submissions regarding the expert evidence should be limited to the appropriateness of such evidence to Hydro One SSM."[1] In the paragraphs below we have limited our comments to Hydro One SSM. The application of the expert reports to Hydro One's entire transmission business will require consideration of a number of issues that are materially different than those for Hydro One SSM. For example, on the benchmarking side, the fact that Hydro One is an outlier on many of the variables[2] is of considerable concern, but that is for the most part a function of size, and Hydro One SSM is relatively small. In addition, it is clear that there is no capital factor in the Hydro One SSM proposal[3], but there is a proposed capital factor in the Hydro One Networks recently filed transmission case (EB-2019-0082).[4]

[1] *Procedural Order No.5*, p.2
[2] Interrogatory Response , Exhibit I, Tab 5, Schedule 31 (SEC #31);Technical Conference Transcript, Vol.2, p.141-142
[3] Interrogatory Response , Exhibit I, Tab 5, Schedule 16 (SEC #16);
[4] EB-2019-0082, Exhibit A, Tab 3, Schedule 1, p.9

With respect to Hydro One SSM specifically, SEC has concluded that the Board should ignore the results reported by Power System Engineering ("PSE")[5], and apply instead the results from Pacific Economics Group ("PEG")[6], but with a significant modification.

There are numerous problems with the PSE reports on inflation, TFP and benchmarking, for example, some of which were explored by SEC on Day 2 of the Technical Conference.[7] SEC has reviewed the critique of the PSE reports in Section 2 of the PEG Evidence[8], and for the most part agrees with their comments. As well, SEC's Technical Conference questions have raised some other issues that call into question the applicability of a 100% U.S. sample to Hydro One, for example, weaker regulatory incentives to control costs in the U.S. relative to Ontario[9], high variability of U.S. data year by year[10], etc. The invention of a new technique, the "loading variable", which is not used in any other jurisdiction, should give the Board pause as well. This is especially true since PSE admits they did not even look at what other studies have used to measure the same cost drivers.[11] Whether or not that is a better approach to measuring climate factors as cost drivers, as opposed to snowfall, wind, or other direct metrics, it is clear that PSE did not do their homework before proposing that variable.

Therefore, SEC concludes that the PSE studies are not sufficiently robust to form the basis for the rates to be set by the Board in this proceeding.

With respect to the PEG analysis, in general SEC agrees with the approach they take with the research. PEG is well-known to the Board, and has over many years produced solid and reliable data and analysis on which the Board has been able to rely on with confidence.

Having said that, SEC disagrees with a key conclusion from PEG. PEG proposes a negative productivity of 0.34%, a positive stretch factor of 0.30%, and a net X factor of 0.00%.[12]

SEC does not agree that negative productivity should be assumed for HOSSM and built into their rate formula. The Board has previously determined when setting the productivity factor for electricity distributors, that even though the evidence showed negative industry TFP, the productivity factor should be set at no less than zero.[13] To do that would be inconsistent with the RRF policy of encouraging continuous improvement and as the Board has said, it "does not believe it appropriate for a rate setting regime to project and entrench declining productivity expectations into the future."[14] Similarly, Ontario Power Generation, in seeking approval for its Price Cap IR for its hydroelectric facilities and only sought approval of a productivity factor of zero, even though its TFP evidence showed negative productivity. In doing so, it expressly recognized the Board's past practice.[15]

SEC strongly supports the Board's view and believes that productivity should not be less than 0.00%. When a stretch factor is added, the result is 0.30% X factor, and that is the result SEC recommends to the Board.

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[5] Exhibit D, Tab 1, Schedule 1, Attachment 1

[6] Exhibit M1

[7] See Technical Conference Transcript, Vol.2

[8] Exhibit M1

[9] Technical Conference Transcript, Vol.2, p.156

[10] Technical Conference Transcript, Vol.2, p.76-83

[11] Technical Conference Transcript, Vol.2, p.138-141, and in particular p.136

[12] Exhibit M1, p.10

[13] *Report of the Board Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors* (EB-2010-0379), Issued on November 21, 2013 and as corrected on December 4, 2013, p.17

[14] *Ibid*

[15] *Decision and Order* (EB-2016-0152 - OPG 2017-2021), December 28 2017, p.124

"Going-in" Revenue Requirement. As detailed in Hydro One SSM's evidence, in GLPT's 2015-16 approved Settlement Proposal, the Board approved creation of an asymmetrical variance account to track the difference between the revenue requirement of the approved and actual in-service additions over those two years (called the In-Service Addition Net Cumulative Asymmetrical Variance Account).[16] If the cumulative amount of in-service additions during 2015 and 2016 was less than the cumulative Board-approved amount, then the revenue requirement impact of the shortfall would be entered in the variance account. Hydro One SSM reports that its cumulative in-service additions were less than the Board-approved amounts in those years by $927,203. This resulted over the two years in an overstated revenue requirement of $143,935.[17]

While Hydro One SSM is seeking to clear the balance in the account, the issue is that since 2016 it is the last approved revenue requirement and thus is the 'going-in' revenue requirement that the RCI will adjust, it is overstated by the revenue requirement impact of underspending in 2015 and 2016 on in-service additions. What makes this different from other cases where rates are set through a price or revenue cap is that an account was created to ensure that customers are held whole for under spending. If the impact of the account is not considered, then Hydro One SSM will not be keeping customers whole for their underspending in 2015 and 2016, as the "going in" revenue requirement for the 2019 RCI adjustment is inflated.

SEC submits that the Board has two options to remedy this issue and ensure customers are held whole.

First, it can reduce the 2016 approved revenue requirement used for the purposes of the 2019 RCI adjustment by the amount added to the account in 2016. SEC requests Hydro One SSM provide that amount in its reply submissions as the amount does not appear to be included in the 2016 DVA continuity schedule included in the evidence.[18]

Second, the Board can deny the proposal to close the account, and continue it through the deferred rebasing period. The account would capture the same 2016 revenue requirement amount, and would be adjusted every year by that years RCI adjustment. The full amount, with usual interest, would then be credited back to ratepayers at the end of the deferral period.

On balance, and recognizing the Board's preference for minimizing the number of deferral and variance accounts, SEC believes that the upfront adjustment is the better choice. It is also more consistent with an IRM rate structure, in which costs are decoupled from rates.

<u>Transmission System Plan</u>

Hydro One SSM filed a Transmission System Plan ("TSP") with its application. The Board included a number of issues related to the appropriateness of the TSP on the Final Issues List Issues (8-11), after agreement was reached among parties. SEC did not oppose the inclusion of the issues on the Final Issues List, but submits that the Board should decline to answer the issues or provide any specific approvals.

In Hydro One SSM's most recent rate application, the Board noted that it had not fulfilled a commitment that its predecessor Great Lakes Power Transmission had made, in a previous approved Settlement Proposal[19], to file an asset management plan at its next rates case. The TSP is in response to that commitment to file one, as contemplated in Issue 1.[20]

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[16] Exhibit E, Tab 1, Schedule 2, p.8-9
[17] *Ibid,* p.9
[18] Exhibit E, Tab 1 Schedule 4, p.4
[19] EB-2014-0238, Settlement Proposal, p.11
[20] *Decision and Order* (EB-2016-0356 - Hydro One SSM), September 28 2017, p.9-10

With respect to the substance of the TSP, the evidence is that the TSP was developed using the current Hydro One SSM asset management and capital planning process[21], which will soon be obsolete as it fully integrates with Hydro One Networks Inc.[22] Hydro One SSM is currently in the first phase of a three phase integration process[23], and the entire process is supposed to take three years.[24]

Whereas Hydro One SSM currently does its own capital planning, after the integration is complete the capital planning for Hydro One SSM and Hydro One Networks transmission facilities will be integrated, using a common approach. [25] Thus, less than half way through the TSP, the planning and asset management process detailed in the application will no longer be relevant. This is not a criticism of Hydro One SSM. It is entirely appropriate to integrate processes with Hydro One Networks after the acquisition. But what will occur is that the filed TSP will soon not reflect the actual planning process and choices used to maintain Hydro One SSM's assets.

SEC notes that the Board does not approve system plans, be it a distribution or transmission system plan. They are filed and evaluated in the context of approving the underlying cost consequences of those plans, such as approval for the addition of capital to rate base or request for an incremental capital module ("ICM").[26] This is consistent with the Board's comments on the recent Enbridge Gas Issues List Decision:

> The OEB has determined that it is appropriate to clarify the scope of the review of the USP and Asset Management Plans (AMPs). The OEB confirms that it will not be approving the USP or AMPs in this proceeding. The review of the USP and AMPs is to provide context for whether the ICMs should be approved. [27]

Hydro One SSM is not seeking approval of any capital spending in this application.[28] For this reason, SEC did not undertake a detailed review of the TSP. Its rates are being determined using a Revenue Cap Index that is intended to decouple revenue from costs. It is not seeking any incremental capital funding this year, and based on its response to interrogatory AMPCO #1, it does not foresee the need for an ICM for the entirety of this deferred rebasing period.[29]

This is not to say there is no benefit of a utility undertaking a system plan and filing it with the Board, even if no relief is to be sought. The process of completing a system plan and being required to file it on the public record is important in ensuring accountability for proper planning. It is why the Board has required utilities, after approval of a MAADs transaction, to file a consolidated system plan after integration, even though it is not tied to any future need for incremental capital.[30]

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[21] Technical Conference Transcript, Vol.1, p.16, 115

[22] Technical Conference Transcript, Vol.1, p.115

[23] Technical Conference Transcript, Vol.1, p.118

[24] Technical Conference Transcript, Vol.1, p.115

[25] Technical Conference Transcript, Vol.1, p.16

[26] *Handbook to Utility Rate Applications*, October 13 2016, p.13-14; This is also similar to how the Board dealt with the review of the gas utilities Cap and Trade Compliance Plans. The Board framework stated that that it would not approve the plans themselves, but will assess them in the context of approving the costs of the plans in rates. See *Regulatory Framework for the Assessment of Costs of Natural Gas Utilities' Cap and Trade Activities* (EB-2015-0363) September 26, 2016, p.7

[27] *Decision and Procedural Order No.* 2 (EB-2018-0305 - Enbridge Gas Inc. 2019), April 1 2019, p.5

[28] Interrogatory Response , Exhibit I, Tab 5, Schedule 4 (SEC #4)

[29] Interrogatory Response, Exhibit I, Tab 4, Schedule 1 (AMPCO #1)

[30] See for example *Decision and Order* (EB-2017-0267 -Newmarket-Tay Power Distribution/Midland Power Utility Corporation MAAD), August 23 2018, p.13

SEC's concern with the Board providing any findings on the DSP in this proceeding is it is not clear what the eventual implications are of such a decision, when Hydro One SSM eventually seeks to add them to rate base in the context of the first consolidated rebasing after the deferral period is over. If the Board approves the TSP, is the implication that the underling forecast expenditures are prudent? If the Board does not approve the TSP, or makes critical comments or suggestions, are the underlying forecast expenditures imprudent?

For example, SEC notes that the evidence is that Hydro One SSM's considerations of alternatives for forecast projects never got to a point where costs were considered.[31] *Not a single* forecast project involved a consideration of the costs of alternatives, as those alternatives were screened out for other reasons earlier in the planning process.[32] SEC is troubled by this, which is likely a symptom of an overly narrow analysis undertaken by Hydro One SSM. But, since no relief is being sought related to those projects, if the Board determines that the consideration for alternatives is not sufficient, what is the implication for Hydro One SSM when it rebases and seeks to add the projects to its rate base?

SEC submits that the Board should not make any findings regarding the current TSP. What it should do is require Hydro One SSM to file with the Board a consolidated TSP with Hydro One Networks, when the integration is complete. This could be done as part of Hydro One Networks 2023-2027 application.

Effective Date

Hydro One seeks an effective date of January 1 2019 even though it only filed its application on July 26, 2018. Hydro One's view is that the proposed effective date is reasonable, arguing that less time was reasonably needed to review the application since it was "less than that of a traditional rebasing application".[33]

SEC does not dispute that the application is less than a traditional cost of service application, but it clearly is much more complex than a traditional rate adjustment application. For example, the application included principally the PSE expert evidence which Hydro One would know would have required OEB Staff or intervenor evidence to review. The application sits somewhere between a cost of service and a mechanistic rates adjustment application.

SEC submits that, on that basis, a reasonable effective date would be February 2019. This would reflect an expected filing date of the mid-point between when the Board expected distributor utilities to file cost of service applications (late April 2018), and Price Cap IR applications (mid-August 2018).[34]

Yours very truly,
Shepherd Rubenstein P.C.

Original signed by

Mark Rubenstein

cc: Wayne McNally (by email)
Applicant and intervenors (by email)

[31] Technical Conference Transcript, Vol.1, p.122-125
[32] *Ibid*
[33] Argument-in-Chief, p.21
[34] https://www.oeb.ca/industry/applications-oeb/electricity-distribution-rates/2019-electricity-distribution-rate