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March 17, 2022

BY E-MAIL TO: Registrar@oeb.ca

To: Ms. Nancy Marconi
Registrar
Ontario Energy Board

Dear Ms. Marconi,

Subject: EB-2021-0243 (Phase 1 – Export Transmission Service Rate) Interrogatories on HONI/IESO Joint Submission

Please find attached my interrogatories in relation to the joint submission from Hydro One Networks Inc. (HONI) and the Independent Electricity System Operator (IESO) regarding the ETS rate.

Sincerely,

Digitally signed by Naren Pattani
Date: 2022.03.17 11:33:50 -04'00'

Naren Pattani
Intervenor

OEB PROCEEDING EB-2021-0243:

Generic Hearing on Uniform Transmission Rates

Export Transmission Service Rate (Phase 1) Interrogatories for HONI & IESO

1.0 INTRODUCTION

These interrogatories are with respect to the joint submission by Hydro One Networks Inc. (HONI) and the Independent Electricity System Operator (IESO) on the Export Transmission Service (ETS) Rate [OEB Proceeding EB-2021-0243]. These interrogatories on the submission (including the submission's attachments) will provide clarifications to inform in the matter of the ETS Rate. For some of the interrogatories below, additional context is provided to explain the rationale for posing a given question.

The interrogatories are provisionally sectioned between HONI (Section 2.0) and IESO (Section 3.0). The agencies are requested to reassign any interrogatories between themselves if deemed appropriate to do so.

2.0 INTERROGATORIES FOR HONI

Interrogatory #1

Ref. Attachment 1: Cost Allocation Methodology (Elenchus Report), Section 6

Question:

Please provide the following clarifications about cost components that are included in the "*Shared Network asset-related costs*" (as defined and used in the reference) which are used in the three options for ETS Rate presented in the report:

(a) What are the criteria for classifying a Network Pool asset as a "*Shared Network Asset*"? What is the fraction (%) of total Network Pool assets that are classified "*Shared Network Assets*" (by measure of Net Book Value of assets, or whatever other unit of measurement used in the methodology)?

(b) Are the following cost components included in the "*Shared Network asset-related costs*": Depreciation, OM&A, Interest Charges, Return on Equity? If any of these components are not included (that is, no cost is included) in "*Shared Network asset-related costs*", what is the rationale for that?

(c) What is the proportion of "*Shared Network asset-related costs*" as a fraction (%) of the total Network Pool Revenue Requirement?

Interrogatory #2

Ref. Attachment 1: Elenchus Report, Section 6 & Table 15

Question:

In your opinion, is the overall methodology sufficiently robust, and is it objective enough so that, in future, given components of (approved) Network Revenue Requirement and historic demand data, the ETS Rate can be reset (i.e., recalculated) without any other subjective decision being required?

Interrogatory #3

Ref. Attachment 2: Jurisdictional Review of ETS (CRA Report)
Appendix A (Expanded Summary of ETS Rates) and
Appendix B (Rate Adders).

Question:

To summarize the Jurisdictional Review:

(a) Is there any jurisdiction that has ***No*** (i.e. "zero") regulated export transmission network charge(s), such as OATT[1] or ETS Rate or

[1] OATT: Open Access Transmission Tariff applicable under FERC rules in USA as per various references in Attachment 2.

equivalent, for exports out of the state or province? If yes, please provide reference.

(b) Is there any jurisdiction where regulated export transmission network charges have been *reduced* specifically because of consideration of energy market attributes or costs (such as congestion management, transmission losses, or other market service costs equivalent to Ontario's Uplift) incurred by export participants? If yes, please provide brief explanation.

Interrogatory #4

Ref. Attachment 2: CRA Report – Table 5 of Appendices A & B
Attachment 3: Market Implications – Section 5

Context:

Section 5 (2nd paragraph) of IESO's Attachment 3, while commenting on the CRA Report (Attachment 2), suggests that it is important to consider other factors when comparing ETS in other jurisdictions, and the subsequent paragraph states that the ETS is just one component (Intertie Congestion Pricing and Uplift[2] being others).

Appendix B of the CRA Report summarizes Rate Adders such as Ancillary Services and other operating costs in non-Ontario jurisdictions, but it does not cover the matter of how the cost of transmission losses and congestion are collected. These are also implications that need to be considered in the Jurisdictional Review for exports tariffs to address IESO's comments.

Question:

In order to summarize if, and how, factors other than regulated Export Tariff Rates are considered in other jurisdictions, please provide brief clarifications noted below.

[2] Uplift recovers operating costs within Ontario such as transmission losses, congestion management, Ancillary Services, etc. See: https://www.ieso.ca/en/Sector-Participants/Settlements/Guide-to-Wholesale-Electricity-Charges

(a) Please confirm that the Rate Adders in Appendix B of Attachment 2 are in addition to Export Transmission Rates shown in Appendix A of the attachment.

(b) Please confirm that in American jurisdictions covered by the CRA Report, Exports as well as loads pay for energy on the basis of Locational Marginal Pricing[3] (LMP) which also includes cost of congestion and losses. Thus, please confirm that, while the Rate Adders in Appendix B do not include cost of congestion and losses, these costs are implicitly included in the energy prices in LMP markets, including at their interties.

(c) Please confirm that Hydro Quebec, another jurisdiction included in Appendix B, also requires payments associated with losses and congestion as per Hydro Quebec's Open Access Transmission Tariff[4,5].

3.0 INTERROGATORIES FOR IESO

Interrogatory #5

Ref. Attachment 3: Market Implications

Question:

Please provide following overview data for the year 2020 (the most recent year in Attachment 3) to give perspective about Ontario's exports:

(a) What was the total energy (TWh) consumed by Ontario loads?

(b) What was the total energy (TWh) (i) exported from Ontario; and (ii) imported into Ontario?

[3] https://www.iso-ne.com/participate/support/faq/lmp.
[4] http://www.oasis.oati.com/HQT/HQTdocs/Tariff_HQT_2017-05-03_en.pdf
[5] http://www.regie-energie.qc.ca/en/consommateur/Tarifs_CondServ/HQT_Tarifs2017.pdf

(c) How much of the energy exported from Ontario was linked[6] to Imports (that is, it was designated a "Wheel Through" transaction from one jurisdiction neighbouring Ontario to another jurisdiction)?

(d) What was the weighted average price of energy ($/Mhr) paid by consumers in Ontario, with and without Global Adjustment? (If the universal weighted average price for all Ontario loads cannot be readily calculated, please provide separately (i) the weighted Hourly Ontario Energy Price (HOEP) that was charged to local distribution companies (LDCs) and non-dispatchable loads, and (ii) weighted average Market Clearing Price (MCP) paid by dispatchable loads.

(e) What was the weighted average energy Price ($/Mhr) paid by Exports? (Depending on data that is readily available, this may be calculated either as weighted average of Hourly Market Clearing Price at Export Zones, or as "total energy charges recovered from Exports divided by total Export energy" paid through the Ontario market).

(f) What was (a) Minimum Export Demand (MW) (b) Maximum Export Demand (MW) and (c) Average Export Demand (MW) in 2020?

(g) For how many hours of the year were Exports (i) more than 0 MW; (ii) more than 1,000 MW; and (ii) more than 2,000 MW?

(h) With respect to exports on the Ontario-New York Intertie and the Ontario-Michigan Intertie (these being the predominant export ties), for how long, in terms of hours or percent of the year, was there Intertie congestion on (i) only one of these Interties; and (ii) both interties?

[6] Page 4 of IESO Training Manual "Introduction to Interjurisdictional Energy Trading" dated January 2014.

Interrogatory #6

Ref. EB-2021-0243 ETS Rate Submission - Page 12, Line 19-20; and Attachment 3: Market Implications: Intertie Congestion Pricing.

Context:

IESO's Inter-Jurisdictional Trading[7] algorithm manages bids and offers for exports and imports, respectively, across Interties with neighbouring jurisdictions. The IESO market collects Intertie Congestion[8] Pricing (ICP) charges from successful interjurisdictional transaction(s) that are allowed to take place on congested Intertie(s) by IESO's dispatch algorithm. For a successful Export on a congested Intertie, these charges are determined by the difference in energy market clearing price between the Ontario zone (figuratively, the price on the Ontario side of the Intertie) and the Export Node of the congested Intertie. To inform the current proceeding, it would be helpful to confirm if there are indeed situation(s) when exports would not have pay any ICP charges.

Questions:

(a) Do Exports attract any Intertie Congestion Pricing (ICP) charge if they take place through intertie(s) that *do not* experience congestion at the time of transaction?

(b) If Exports *do not* attract ICP Charge when there is no congestion, what fraction (percentage) of total Exports in 2020 did *not* attract ICP charge because there was no congestion on the respective intertie(s)?

(c) What fraction of Wheel Through transactions in 2020 (i.e Export that was designated as a linked transaction from one jurisdiction

[7] Section 4 of IESO Training Manual "Interjurisdictional Energy Trading" dated January 2014.
[8] Intertie Congestion manifests when the power flow requested by importers/exporters across an Intertie is more than the capability of the Intertie. In this case, IESO's dispatch algorithm determines which transactions can be consummated (successful), and which cannot take place so that the Intertie capacity limit is respected.

neighbouring Ontario to another jurisdiction) did *not* attract ICP charge on the Export side because there was no congestion on intertie(s)?

Interrogatory #7

Ref. Attachment 3: Market Implications, Table 1 – Congestion Rents; and Table 2 - TRCA Historical Flows
IESO's Planning Outlook, December 2021

Context:

Table 1 indicates that Congestion Rents on Exports, also called ICP Charges, have decreased from $ 208 million to $ 99 million between 2017 and 2020. Table 2 indicates that disbursements from the Transmission Rights (TR) Clearing Account (TRCA), which also includes consideration of import congestion and the TR Auction[9], have reduced from $ 173 to $ 118 million in the same time frame.

IESO's Planning Outlook, December 2021, indicates on Page 5 that there is "potential for considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirements, ongoing nuclear refurbishment outages, and expiring supply contracts and commitments" and that "with the pandemic recovery well underway, the IESO's forecasts show steady average growth of about 1.7 per cent a year". It also indicates on Page 6 that "potential energy shortfalls are forecast to begin in 2026 and grow substantially …". (The Planning Outlook also indicates, on Page 47, that (Ministry of) "ENERGY has asked the IESO to enter into contract negotiations with ITC on the Lake Erie Connector project which would establish a new 1,000 MW high voltage bi-directional underwater transmission intertie").

Question:

In view of the medium-and-long-term forecast of decrease in supply sources and the forecast of moderately increasing load in Ontario:

[9] IESO Training: Transmission Rights Workbook, September 2020

(a) Is it conceivable that the Congestion Rents (ICP Charges) for Exports may decrease in the medium and/or long term?

(b) Is it conceivable that the existing 6,020 MW export capacity[10], bulk of which is along the southern border with the US, (with possible addition of 1,000 MW capacity), may in future be generally sufficient to meet export requirements most of the time so that the Congestion Rents and TRCA with respect to Exports may approach zero ("nil") irrespective of whether the ETS Rate stays the same or is increased to be on the order of $ 2 to $ 5 per MWhr?

Interrogatory #8

Ref. Attachment 3: Market Implications of Exports - Page 8

Question:

Are Operational Benefits identified with respect to Ancillary Services, Regional Reliability, Emergency Events, & System Flexibility because of the *existence of the heritage interconnection facilities*, or are they because *exports are taking place*?

If these benefits are because of the physical interconnection facilities, please explain the rationale behind characterizing the operational benefits above as due to intertie trading? Is the matter of operational benefits, as articulated in the referenced report, relevant to the setting of the ETS Rate?

Interrogatory #9

Ref. Attachment 3: Market Implications – Table 1 (Page 9), and Page 14
IESO's Planning Outlook, December 2022

[10] HONI Exhibit EB-2021-0110, Page 9, Line 1 to 2, shows the existing export capacity.

Context:

With respect to the Avoided System Costs noted in Table 1 and in the last paragraph of Page 14, exports indeed help absorb surplus baseload (and renewable) generation when it exists. The Avoided System Costs shown in the Table 1 (with footnote “13”) are laudatory and they are (presumably) the value of total surplus baseload generation sold; that is, they are the absolute value of energy cost recovered by surplus baseload generation that is sold in the Export market.

For the purpose of the current proceeding, it is of interest to determine how much, if any, of the surplus baseload generation would be expected to remain unsold if the ETS Rate were to increase from $ 1.85 to the order of, for example, $ 2 to $ 5 per MWhr.

The Market Rules enable generators to manage surplus baseload generation by submitting lower prices for generation offers[11] so that they may get scheduled to meet the total demand including exports; alternatively, generators may register as self-scheduling and intermittent generators if they wish to be “price takers”. All generators that are scheduled, including those that may have offered lower prices for assurance of being scheduled and those that choose to be “price takers”, get paid the Market Clearing Price which is determined by the highest generation offer price accepted by the IESO to meet the total demand (including Exports and Domestic Demand).

Questions:

(a) Given the facility to manage surplus baseload generation by submitting lower offer prices in the energy market or by being “price takers” (with such generation also then being paid at the highest offer rate of all generation accepted for dispatch), how much will the *relative* utilization of surplus baseload generation be impacted if the ETS Rate were to be of the order of $ 2 to $ 5 per

[11] Section 3 of IESO Training Manual “Introduction to Ontario’s Physical Markets” dated February 2014.

MWhr compared to $ 1.85 per MWhr today?

(b) In view of the medium-and-long-term forecast of decrease in supply sources and moderately increasing load in Ontario (refer to Interrogatory #7 above), is it conceivable that the issue of surplus baseload generation may ebb over the next few years?

Interrogatory #10

Ref. Attachment 3: Uplift on Table 1 of Page 8;
Page 10 (2nd bullet), and Page 14 (2nd last bullet).

Context:

The references to Uplift[12] in Attachment 3 need some clarification with respect to whether payment of Uplift by Exports can be considered a benefit to Ontario consumers. This clarification is attempted below.

It is necessary to distinguish between *grid congestion*[13] *management costs* included in the Uplift, on one hand, and the ICP Charges[14] payable by Exports if and when there is Intertie congestion[15]. The Uplift costs collected by IESO includes, among other operating costs, the grid congestion management costs that are *not* related to, nor included in, the ICP Charges. The ICP Charges payable by Exports are determined solely by the difference in energy market clearing price between the Ontario zone (figuratively, the price on the Ontario side of the Intertie) and the Export Node of the congested Intertie. The ICP charge is *not* based on, *nor* is it determined by, grid congestion costs or any other component of Uplift costs that occur upstream from the Intertie, *irrespective of how the*

[12] https://www.ieso.ca/en/Sector-Participants/Settlements/Guide-to-Wholesale-Electricity-Charges

[13] Grid congestion management is sometimes required upstream of the Interties. It manifests because, with economic dispatch of generation and imports, power flows to domestic loads and exports would sometimes result in one or more circuits being overloaded. In such cases, IESO's operators would astutely redispatch generation within the province to eliminate such overloads. This redispatch results in increased costs that is collected through Uplift.

[14] Section 4 of IESO Training "Interjurisdictional Energy Trading"

[15] Footnote 8 for Interrogatory #6 explains Intertie Congestion.

export power has been conveyed to the Intertie from a (remote) Ontario generator or from import at the other end of the province.

Suppose the Grid is operating with exports taking place, for example, across Ontario-New York and/or Ontario-Michigan borders. Under such scenario, whether or not there is congestion on the Intertie(s):

- If there is grid congestion *upstream* of the border (for example on transmission lines between Sudbury and Toronto areas and/or transmission lines between London and Chatham areas), and if that congestion is managed by rescheduling generation within Ontario, the increased cost for generation rescheduling to serve loads and Exports is included in the Uplift.

- If there is a need for Ancillary Services such as reactive power to support voltage in southern Ontario or for additional spinning and operating reserves in Ontario, the increased cost for such Ancillary Services to support power transfer to loads and Exports is included in the Uplift.

- As for grid congestion costs and Ancillary Services costs (as described above), the Uplift includes the cost of transmission network losses incurred while power is being transported from generation/imports to both export nodes and domestic loads.

Question:

If the Uplift charges recover operating and market service costs (including transmission losses, grid congestion, Ancillary Services, among others) to deliver power to the Export nodes as well as for supplying Ontario load, and if Exports then have to pay Uplift charges as per Market Rules which allocate respective Uplift costs between Domestic Loads and Exports, then please explain the rationale behind labelling "*Uplift collected from Exports*" as an "*Economic Benefit of Exports*" on Page 9, rather than considering these Uplift costs paid by Exports as the allocated share of Uplift costs due to Exports?

Interrogatory #11

Ref. Attachment 3 - Market Implications of Exports

Context:

The context of this or any other interrogatory is *not at all* to suggest that exports should be discouraged. Indeed, there is no question, nor any doubt, that Ontario should have fair and efficient rules and regulatory mechanisms for electricity exports to take place.

An analysis of market implications of exports on Ontario consumers, such as that shown in Attachment 3, would be more complete if some consideration is included about the impact of exports on energy prices for Ontario consumers. A detailed objective assessment of such an impact, for example by analysing IESO's market data from past few years, would be onerous and may require considerable resources. At this time, for efficiency, it would be instructive and relatively easy to obtain a cursory, yet objective, understanding of the relationship between exports and energy prices by examining a snapshot of IESO's data.

Question:

For the 12 hours (7 AM to 7 PM) of any midweek working day in February 2020 and in August 2020, please provide the following data from actual generation/imports offers and demand based on data in the IESO market:

(a) Hourly Ontario Demand (MW)

(b) Hourly Export Demand (MW)

(c) Hourly Ontario Energy Price (HOEP) ($/Mhr), excluding Global Adjustment, during the hour.

(d) An estimate, based on the actual Stacking Order of Generation Offers and Total Demand, of what the HOEP would have been if the exports were lesser by 1,000 MW during the hour.

(If IESO does not have this historical data, please provide similar data for 12 hours of any weekday going forward (that is, using the actual generation offers and demand data on any weekday going forward from now)).

END