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Frank D'Andrea
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BY EMAIL AND RESS

October 14, 2021

Ms. Christine E. Long
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Long,

EB-2021-0243 – Generic Hearing on Uniform Transmission Rates-Related Issues and the Export Transmission Service Rate

Pursuant to the OEB's Procedural Order No. 1 in EB-2021-0110 and Hydro One Networks Inc. letter dated September 30, 2021, please find enclosed a joint submission from Hydro One Networks Inc. and the Independent Electricity System Operator regarding the ETS rate.

Sincerely,

Frank D'Andrea

EXPORT TRANSMISSION SERVICE RATES

A. INTRODUCTION

Hydro One Networks Inc. ("Hydro One") filed an application with the Ontario Energy Board (OEB) on August 5, 2021, seeking approval for changes to the rates that it charges for electricity transmission and distribution, for the 2023 to 2027 period (EB-2021-0110). As Export Transmission Service (ETS) Rates have been established by the OEB through Hydro One transmission rate filings since market opening, Hydro One's application in EB-2021-0110 included evidence relating to ETS Rates, including certain reports that it had previously been directed by the OEB to prepare and file. However, in Procedural Order #1 issued in EB-2021-0110 on September 17, 2021 (the "Procedural Order"), the OEB determined that instead of determining the ETS Rate through Hydro One's application it would instead commence a separate, generic proceeding on its own motion (EB-2021-0243) to review a number of issues related to Uniform Transmission Rates (UTRs) and that it would deal with the setting of the ETS Rate as the first phase of that generic proceeding.

In the Procedural Order, the OEB referred to the evidence filed by Hydro One on the ETS Rate in EB-2021-0110 and requested that Hydro One and the IESO provide clarification of their recommendations for the ETS Rate. The OEB also indicated that the reports and other evidence filed by Hydro One on ETS Rates in EB-2021-0110 and the requested clarifications from Hydro One and the IESO would form part of the record and be considered in the generic proceeding. Therefore, to facilitate the generic proceeding, this document includes (a) a summary of relevant background information regarding the ETS Rate, (b) clarifications from Hydro One and the IESO as to their recommendations on the ETS Rate, and (c) copies of three reports relating to ETS Rates which were previously filed in EB-2021-0110.

B. BACKGROUND

This section provides an overview of ETS Rates, including how they have been determined historically, how they have related to Hydro One's transmission revenue requirement and UTRs, the OEB's directions for Hydro One to prepare and file certain reports on ETS Rates, and the treatment of the ETS Rates issue in Hydro One's most recent transmission revenue requirement application.

1. What is the ETS Rate?

ETS is defined in the Market Rules as meaning the transmission service relating to the use of the IESO-controlled grid for the transmission of energy out of the IESO-control area and into a neighbouring transmission system and in respect of which charges are required to be collected by the IESO pursuant to section 4 of Chapter 10. That section of the Market Rules provides that the IESO is required to collect charges for ETS from each transmission customer that uses the IESO-controlled grid for the transmission of energy out of the IESO control area, but that charges for network service will not be applicable to market participants in respect of the use of the IESO-controlled grid for such transmission. Section 4.5 of Chapter 10 of the Market Rules specifies that the rates and charges, if any, for ETS to be applied to the transmission customers that use the IESO-controlled grid to transmit energy out of the IESO control area to neighbouring transmission systems shall be established by the OEB from time to time pursuant to the *Ontario Energy Board Act, 1998*.

2. How has the ETS Rate Been Determined Historically?[1]

In proceeding RP-1999-0044, the OEB considered and determined the ETS Rate that was to be implemented at market opening. In its Decision with Reasons in that proceeding, dated May 26, 2000, the OEB summarized the various arguments presented by stakeholders on what the ETS Rate should be. The OEB decided that, as an interim measure, the ETS rate should be fixed at \$1.00/MWh. This was considered to be a reasonable compromise between the competing interests

[1] This summary of the history of ETS Rate determinations is largely derived from the background information provided in a 2014 report by Elenchus Research Associates, entitled *Export Transmission Service Rate – Cost Allocation Methodology*, dated May 7, 2014.

and proposals presented by stakeholders in the proceeding on what was described as a complex and contentious issue. Among other things, the contention emerged from what stakeholders believed should be the basis of, or purpose of, the tariff design and what ought to be an appropriate charge level to help defray the costs to domestic customers for the use of the network transmission facilities to facilitate export and wheel-through transactions. The OEB directed that Hydro One monitor and report in its next rate proceeding as to how the export market was functioning and the developments in interconnected jurisdictions and whether the ETS Rate should be reviewed.

Hydro One retained R. J. Rudden to perform a "Jurisdictional Survey of Export and Wheel-through Service Rates". The report regarding the survey was issued on June 26, 2006 and was filed by Hydro One for consideration in proceeding EB-2006-0501.[2] In that proceeding, the OEB approved a settlement agreement which maintained the ETS Rate of $1.00/MWh. In the settlement agreement, the IESO was identified as being the entity that should be responsible for undertaking a study on the appropriate ETS Rate. The settlement agreement stated that:

> ...the IESO should now be identified as (the) entity responsible to pursue and negotiate, with neighbouring jurisdictions, acceptable reciprocal arrangements with the intention to eliminate the ETS tariff, and study the appropriate ETS tariff, including those options identified in H1/T5/S1. The IESO will seek input from market participants and interested intervenors in this proceeding and keep the parties informed of the progress of negotiations and the study. It is agreed that the IESO will make its report available to the Board upon completion which will be no later than June 1, 2009 with the results of reciprocal arrangement negotiations and the study including recommendations for an appropriate ETS tariff. Hydro One Networks Inc. remains responsible for seeking changes to its approved transmission revenues and rates and will do so as part of the 2010 transmission rate-resetting process period, following the publishing of the study.[3]

The IESO retained Charles River Associates ("CRA") to perform a quantitative analysis of the future effect of several ETS Rate scenarios, with respect to exports and wheel-through volumes, ETS tariff revenue, and the Hourly Ontario Energy Price. The IESO's ETS study and

[2] EB-2005-0501, Exhibit H1, Tab 5, Schedule 2.
[3] EB-2006-0501, Exhibit M, Tab I, Schedule 1, p. 17, April 3, 2007.

recommendation was filed with the OEB on August 28, 2009 and was reviewed in proceeding EB-2010-0002.[4] The IESO study reviewed four alternatives for setting the ETS rate: (i) status quo, (ii) equivalent average network charge, (iii) reciprocal treatment, and (iv) elimination. The IESO recommended the status quo alternative to the OEB.

In its Decision with Reasons in proceeding EB-2010-0002, the OEB concluded (at p. 75) that an additional study was required. The OEB stated:

> The Board concludes therefore that the most pressing requirement is that a genuinely comprehensive study be undertaken to identify a range of proposed rates and the pros and cons associated with each proposed rate in time for the next transmission rate application. In the Board's view, the most appropriate party to undertake this study is the IESO. In procuring the study, the IESO should circulate the terms of reference to the Applicant and the intervenors of record in this case with a view to ensuring that the resulting study will provide detailed analysis on the issues. This review of the terms of reference is not intended to be a strategic negotiation, but rather a technical exercise to ensure that the scope of the project is sufficiently broad and well-defined to ensure a useful and appropriate outcome. Work on this study should begin soon, to ensure completion well in advance of the time for the filing of the next transmission rates application by Hydro One.

The OEB in the same proceeding increased the ETS Rate to $2.00/MWh, based on the following rationale:

> Accordingly, the Board will direct that a change be made to the ETS rate for 2011 and 2012, increasing the rate to two dollars per MWh. In making this change the Board seeks to recognize the directional preference of the CRA study, and the absence of any particular analytical underpinning for the current rate. Subsequent panels assessing the level of this rate should not, however regard this new rate as having any particular precedential value. It is the Board's view that the new rate has more analytical support than the status quo, but that in order to arrive at a genuinely robust and valid rate, more study is required.

[4] EB-2010-0002, Exhibit H1, Tab 5, Schedule 2, Attachment 1.

In response to the OEB directive, the IESO engaged CRA to conduct a further review of the ETS Rate. CRA described its study as follows:

> CRA has reviewed tariff rates and structures in neighbouring markets; assessed the proposed rate options on the basis of conformance with generally accepted rate-making principles (consistency with neighbouring markets, simplicity, fairness and efficiency), and; quantified the impact of each of the options on Ontario consumers, producers, and the Ontario market as a whole. This study also reports impacts of each option on exports and imports, market and total bill prices, export tariff revenue, production costs, carbon emissions, and the frequency and duration of Surplus Baseload Generation ("SBG") periods.[5]

The rate options considered were: (a) status quo, (b) elimination, (c) equivalent average network charge, and (d) tiered rates (two alternatives). The CRA study was dated May 16, 2012 and was filed and reviewed in OEB proceeding EB-2012-0031.[6] In the IESO's submission to the OEB in that proceeding, the IESO indicated that none of the ETS tariff options materially impact reliability, but that the elimination of the tariff would best promote the efficient operation of the wholesale electricity market.

In its Decision with Reasons in EB-2012-0031, dated June 6, 2013, the OEB directed Hydro One to include a proposal for an appropriate cost-based ETS Rate, with supporting rationale, in its next transmission rate application to the OEB. More particularly, the OEB stated in that decision (at p. 9):

> The Board will require Hydro One to perform a cost allocation study to establish a cost basis for the ETS rate. Some parties have suggested that such a study would be prohibitively costly. However, the Board accepts the Elenchus testimony that a study could be properly scaled to address the magnitude of the issue and could be completed for a reasonable cost. The Board expects that this study will be completed in time for Hydro One's next cost of service transmission rate application. While Hydro One has the responsibility for completing this study, the Board expects that the IESO will assist Hydro One as required to fully address the ETS rate issue.

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[5] See Export Transmission Service (ETS) Tariff Study Prepared for the IESO by Charles River Associates dated May 16, 2012, page i, as filed in EB-2012-0031, Exhibit H1, Tab 5, Schedule 2, Appendix B, page 3.

[6] EB-2012-0031, Exhibit H1, Tab 5, Schedule 2, Appendix B.

In response to the directive, Hydro One engaged Elenchus Research Associates to prepare the cost allocation study. The Elenchus study was dated May 7, 2014 and was filed by Hydro One in EB-2014-0140.[7] The key parameters of Elenchus' recommended methodology for allocating costs to ETS service (the May 2014 Methodology) were as follows:

- Allocate dedicated assets used to serve export customers and related expenses to the export customer class;
- Shared Network OM&A Costs are allocated to export customers, but no Shared Network asset related costs are allocated to export customers;
- Allocate OM&A expenses related to the use of shared assets to export customers using composite assets as allocator; and
- Utilize the 12 Coincident Peak (CP)[8] as the allocator in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses.

Based on the May 2014 Methodology, Elenchus recommended an ETS Rate of $1.70/MWh for 2015 and 2016 as being reflective of the cost of providing ETS.

For the purpose of reaching a settlement, all parties agreed to an ETS Rate change from the $2.00/MWh that was in effect at the time, to $1.85/MWh. The OEB approved the settlement in EB-2014-0140, thereby approving $1.85/MWh as the ETS Rate for 2015 and 2016. The OEB subsequently approved the continuation of the ETS Rate at $1.85/MWh for 2017 and 2018 (EB-2016-0160), for 2019 (EB-2018-0130), and most recently for 2020 to 2022 (EB-2019-0082).

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[7] EB-2014-0140, Exhibit H1, Tab 5, Schedule 1, Attachment 1.
[8] Domestic and Export Demand at Ontario system peak.

3. OEB Directions in EB-2019-0082

In its Decision on Hydro One's 2020 to 2022 transmission rate application (EB-2019-0082), the OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates".[9] The OEB directed Hydro One to provide an ETS study using a cost allocation methodology that includes the allocation of shared network costs to exporters in its next transmission rebasing application.

In addition, the OEB stated that it would be assisted by an updated jurisdictional review that provides the ETS rates in other jurisdictions, the rationale behind those rates and market implications. Recognizing that the operation of the electricity market is the responsibility of the IESO rather than Hydro One, the OEB indicated its expectation that Hydro One discuss the approach to the jurisdictional review with the IESO and OEB staff to determine the best approach to complete the review before Hydro One's next transmission rebasing.

4. Hydro One's Filings on the ETS Rate in EB-2021-0110

In response to the OEB's directions from EB-2019-0082, Hydro One filed as part of its pre-filed evidence in EB-2021-0110, an ETS cost allocation study, prepared by Elenchus and dated July 21, 2021, which uses a cost allocation methodology that includes a number of options for the allocation of shared network costs to exporters. A copy of the 2021 Elenchus report is provided as **Attachment 'A'** hereto. Hydro One also provided an updated ETS jurisdictional review, prepared by Charles River Associates (CRA) and dated March 29, 2021. A copy of the 2021 CRA report is provided as **Attachment 'B'**. In addition, through Hydro One's discussions with the IESO and OEB staff, it was agreed that the IESO would provide comments, as part of Hydro One's pre-filed evidence in EB-2021-0110, on the implications for Ontario's electricity market of changes to the ETS Rate. A copy of the IESO's July 2021 comments is provided as **Attachment 'C'**. Hydro One notes that it has taken steps to ensure that the principal authors of the 2021 Elenchus report and the 2021 CRA report will be available for discovery or as otherwise may be required in the generic proceeding.

[9] EB-2019-0082 Decision and Order, page 180.

(a) 2021 Elenchus Report

The 2021 Elenchus report was intended to supplement the May 2014 Methodology to identify cost-based methodologies that could potentially be used for allocating Shared Network Asset-related costs to exporters.

Elenchus reviewed the May 2014 Methodology to calculate the ETS Rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB report on Pole Attachment Charges[10] and the OEB Decision and Order on Hydro One's transmission application (EB-2019-0082), as well as surveyed whether other jurisdictions use cost allocation principles for the purpose of allocating shared network costs between domestic and export classes.

The 2021 Elenchus report considers three methodologies in developing a cost-based cost allocation for Shared Network Asset-related costs to export customers.[11] The three methodologies allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets, with adjustments to the Shared Net Fixed Assets allocator applied to each scenario. The Shared Net Fixed Assets allocator is underpinned by the 12 Coincident Peak (12CP), which represents the relative export and domestic class demands in the peak hours of each month. The portion of Shared Net Fixed Assets allocated to the export class is adjusted for each option as described below:

1. Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
2. Apply an adjusted Shared Net Fixed Assets allocator with export 12 CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
3. Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

[10] March 22, 2018 report on Pole Attachment Charges (EB-2015-0304)

[11] The May 2014 Elenchus report directly allocated the assets and costs dedicated to interconnect directly to the Export class. The 2021 Elenchus report proposes a refinement to that methodology to include the contribution of imports, which serve domestic load. The details are provided in Section 6.2 of the Elenchus report.

An allocation on the basis of Shared Net Fixed Assets with unadjusted export demand volumes could be justifiable as the historical export hourly usage data will reflect the extent to which export customers are curtailed in peak hours. The 50% method is aligned with the OEB's decision on Pole Attachment Charges. The curtailment percentage method provides a more direct link between the reduction of Shared Network Asset-related costs allocated to exports and the number of hours in which they are curtailed.

As in the May 2014 Methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS Rate be adjusted to include other transmitters' approved revenue requirements.[12] The ETS rates that result from applying these methodologies using Hydro One's 2023 revenue requirement and actual 2020 load and consumption data, as well as the associated adjusted ETS rates, are provided in the following table:

Methodology	Allocator for Shared Network Asset-related costs		ETS Rate ($/MWh)	Adjusted ETS Rate ($/MWh)
	Domestic Share	Export Share		
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.07	$6.54
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40	$3.66
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03	$5.42

While the 2021 Elenchus report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, the view expressed by Elenchus is that whether or not the OEB should change ETS rates to reflect those network costs is a broader policy question for the OEB to determine.

[12] Rates are adjusted by 7.77%, calculated as the sum of Hydro One's 2023 proposed Network Revenue Requirement and the Network Revenue Requirements of all other transmitters (as per EB-2020-0251) divided by Hydro One's proposed 2023 Network Revenue Requirement.

(b) 2021 CRA report

Hydro One engaged CRA to update its 2012 Jurisdictional Review[13] to reflect current export transmission service rates in other jurisdictions, the rationale behind those rates and how market implications are considered in the setting of export transmission service rates in those jurisdictions. CRA found that ETS rate levels in general have increased since 2012 but display no changes in rate design. The observed rate level changes are attributable to inflation and transmission expansion since 2012. The regulatory rationale for rate design differs across the markets that were studied. Most jurisdictions included in the 2021 CRA Study apply Open Access Transmission Tariff (OATT) rates for export services, which promote competitive and non-discriminatory transmission access. A summary of the 2020 rates in each jurisdiction for Firm and Non-Firm Point-to-Point (PTP) and Export Transmission Services (ETS) is provided as Appendix A of the 2021 CRA Study.

(c) 2021 IESO comments

The IESO's comments on the Market Implications of the ETS Rate include an overview of intertie trading in Ontario, discuss the implications of an increased ETS Rate for the Ontario market, and comment on jurisdictional comparisons and the suitability of the OEB's pole attachment approach to the setting of the ETS Rate. The IESO commented that each of the ETS Rate options identified in the 2021 Elenchus report would represent a significant increase over the approved existing ETS Rate of $1.85/MWh, and that the market implications of a higher ETS Rate would be expected to include a corresponding decrease in Intertie Congestion Pricing revenues, a reduction of exports and adverse impacts to the operational/economic benefits that exports provide. The IESO states that "revenue from the ETS is only one component of the value that Ontario receives from exports and historically has been the smallest component of the economic benefits associated with exports. When setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will

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[13] Export Transmission Service Tariff Study Review of Rates in Neighbouring Markets, Prepared for: The Independent Electricity System Operator dated May 16, 2012.

reduce the value of interties, leading to less system flexibility and higher costs for Ontario consumers."

5. Relationship Between ETS Rate, Transmitter Revenue Requirement and UTRs

The IESO collects charges from exporters based on the OEB-approved ETS Rate then in effect, and remits those amounts to Hydro One. Hydro One is the only Ontario transmitter that owns and operates the intertie facilities that are accounted for in the historically approved ETS Rates. The revenue that Hydro One requires through transmission rates (i.e. its transmission revenue requirement) has historically been based on its total proposed transmission revenue requirement, offset by various Other Revenues including the revenues it forecasts to be received from the IESO for providing export transmission service based on the approved ETS Rate then in effect. For example, based on the current ETS Rate of $1.85/MWh, Hydro One's forecasted ETS revenues during the 2023 to 2027 period are approximately $37M per year. Consequently, Hydro One's transmission rates revenue requirement, which it recovers through UTRs, is approximately $37M less each year than it otherwise would be without those ETS revenues. As a result, any changes in the approved ETS Rate would have a neutral impact on Hydro One's overall transmission revenues because an increase or decrease in the ETS Rate would result in an equal and opposite increase or decrease in the amount by which Hydro One's rates revenue requirement is offset for purposes of recovery through UTRs.

C. HYDRO ONE POSITION AND RATIONALE

Hydro One recognizes that the current ETS Rate was established through an approved settlement proposal and is therefore not entirely cost-based[14], and that the level of the ETS Rate impacts both transmission rates for electricity customers in Ontario and costs for exporters. Hydro One also understands from the IESO's comments filed in EB-2021-0110 that changes in the ETS Rate can impact the volume of export transactions in the Ontario electricity market, which can impact the economic efficiency of the market. Given these considerations, and the fact that changes in the

[14] In EB-2014-0140, for the purpose of reaching a settlement, all parties agreed to an ETS Rate of $1.85/MWh, which was the mid-point between the proposed cost-based rate of $1.70/MWh and the $2.00/MWh that was in effect at the time.

approved ETS Rate would have a neutral impact on Hydro One's overall transmission revenues as described above, Hydro One does not make any recommendations on a specific ETS Rate. While Hydro One desires the outcome that is best for its customers, it is not in a position to determine what ETS Rate, if any, would ultimately result in the best overall outcome for its customers. As such, having regard to the purposes of the IESO under the *Electricity Act* and of the OEB under the *Ontario Energy Board Act*, Hydro One defers to the IESO's expertise and responsibility to advise on the potential impacts of changes to the ETS Rate and the recommended ETS Rate from a market operations perspective, and to the OEB's expertise and responsibility with respect to the balancing of the various competing interests in setting the ETS Rate. Of course, Hydro One has endeavored, and will continue, to support the OEB's decision-making by providing the necessary evidence regarding a cost-based rate.

D. IESO POSITION AND RATIONALE

In response to the OEB direction in Procedural Order #1, EB-2021-0110, the IESO provides the following submission.

The ETS rate is a fixed charge applied on all exports regardless of market conditions. In addition to paying the ETS rate, Ontario exporters also contribute to the costs of the transmission system through the Intertie Congestion Price (ICP), a dynamic charge set based on its market value to traders, administered through the IESO-administered market.

As discussed in the IESO's evidence, "Market Implications of the Export Transmission Service Rate", when the OEB is setting the ETS rate, consideration should be given to the operational and economic benefits provided by exports. From an operational perspective, exports benefit Ontario by enabling the IESO to address power system needs and reliably manage the grid during changing system conditions. From an economic standpoint, exports of energy from Ontario have contributed approximately $330-520 million annually to Ontario in market revenues which contribute to fixed system costs and avoiding incremental system costs. This economic value includes approximately $36 million per year from ETS charges collected and approximately $160 million annually of ICP revenue the majority of which is returned to domestic consumers.

Exports are price-sensitive. A higher ETS charge would reduce export volumes, directly impacting the amount of ETS and ICP revenue collected. Even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. For example, prior analysis has shown that increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes[15], which would reduce ICP revenues and could reduce total ETS collected. In addition to the financial impact, a material reduction in exports would create operational challenges, leading to increased hydroelectric spill, additional curtailments of renewable generation and potential nuclear manoeuvers to maintain reliability.

In EB-2012-0031, the IESO concluded that, based on the 2012 Charles River Associates (CRA) study[16], reducing the ETS rate to zero "would best encourage the efficient use of electricity and promote economic efficiency in the generation, transmission and sale of electricity". There was however uncertainty at the time as to the extent to which ICP revenues would defray domestic consumer costs and, as the IESO acknowledged, this uncertainty meant the zero ETS rate would result in increased consumer costs unless ICP revenues were allocated to consumer costs. Since the 2012 CRA study, the IESO has passed a number of market design changes that have clarified how ICP revenues reduce transmission costs for ratepayers and now results in the vast majority of congestion funds to be disbursed to domestic customers to offset their transmission costs.

For these reasons, the IESO maintains the view that reducing the ETS rate to zero would best encourage the efficient use of electricity and promote economic efficiency in the Ontario market. However, the market has operated with the ETS rate near its current level since market open and the IESO is mindful there are other relevant considerations the OEB must make when setting an ETS rate. Therefore, the IESO recommends the rate be set at zero or no higher than the current $1.85/MWh to maximize efficient use of electricity and promote economic efficiency in the Ontario market.

[15] IESO internal analysis based on data presented in Export Transmission Service Tariff Study, Charles River Associates, May 16, 2012, pages 18-20.

[16] Export Transmission Service Tariff Study, Charles River Associates, May 16, 2012.

E. ATTACHMENTS

Attachment 'A'	Elenchus Research Associates Inc., *Export Transmission Service Rate Cost Allocation Methodology*, July 21, 2021
Attachment 'B'	Charles River Associates, Jurisdictional Review of Export Transmission Service Rates Study – Final Report, March 29, 2021
Attachment 'C'	IESO, Market Implications of the Export Transmission Service Rate, July 2021

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Export Transmission Service Rate Cost Allocation Methodology

Report prepared by
Michael Roger, Andrew Blair
Elenchus Research Associates Inc.

Report Prepared for:
Hydro One Networks Inc.

July 21, 2021

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EXECUTIVE SUMMARY

Hydro One Networks Inc. ("HONI") retained Michael Roger and Andrew Blair of Elenchus Research Associates Inc. ("Elenchus") in order to supplement the May 2014 cost-based methodology to establish the Export Transmission Service ("ETS") rate in Ontario, by identifying cost-based methodologies that could be used for allocating Shared Network Asset-related costs[1] to exporters and which take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled.

The cost-based methodologies that have been identified in this report are intended to inform the OEB's decision-making on ETS rates going forward.

Elenchus reviewed the May 2014 cost-based methodology to calculate the ETS rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB's March 22, 2018 report on Pole Attachment Charges (EB-2015-0304) and the OEB's Decision and Order on HONI's most recent transmission revenue requirement application (EB-2019-0082), and surveyed how export rates are set in other jurisdictions.

Based on the information provided by the IESO on how exports are treated compared to domestic customers, exporters are able to use the transmission assets much of the time, in spite of the fact that exports are subject to more service interruptions than domestic customers. In the past few years, exports have been affected by fewer and fewer service interruptions and in 2019 and 2020 curtailments were close to 20% of the hours. In the five peaks hours in each of the past five years, exports were curtailed in 11 out of the 25 hours and 10% of volumes were curtailed in those hours.

As stated by the OEB in its report on Pole Attachment Charges, when developing a cost-based methodology, consideration can also be given to the value that users obtain from leveraging an established network. This means that there should not be users of a shared network that do not pay their fair share of costs for use of the shared network, also referred to as "free riders".

[1] Asset-related costs include depreciation, interest, ROE, and taxes.

Since exporters are able to use the transmission system much of the time, even at the times of the Ontario system peak, Elenchus believes that a reasonable basis exists for Shared Network Asset-related costs to be allocated to exports based on the principle of cost causality.

Even though export demand needs are not taken into account when HONI designs the transmission system and the IESO does not factor exports into its reliability planning assessments, the fact that exporters can use the transmission system much of the time supports the allocation of Shared Network Asset-related costs in a cost allocation methodology to exports. Elenchus considered a range of potential cost-based methodologies.

Elenchus considers the following three methodologies to be appropriate options to allocate Shared Network Asset-related costs to the export class. The three methodologies allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets, with adjustments to the Shared Net Fixed Assets allocator applied to each scenario. The Shared Net Fixed Assets allocator is underpinned by the 12 Coincident Peak ("12CP")[2] allocator.

1) Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
2) Apply an adjusted Shared Net Fixed Assets allocator with export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
3) Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

[2] The 12CP allocator represents the relative Export and Domestic class demands in the peak hours of each month. Please see the full description in Section 3.4.

An allocation on the basis of Shared Net Fixed Assets with unadjusted export demand volumes could be justifiable as the historical export hourly usage data will reflect the extent to which export customers are curtailed in peak hours.

The 50% method is aligned with the OEB's decision on Pole Attachment Charges.

The curtailment percentage method provides a more direct link between the reduction of Shared Network Asset-related costs allocated to exports and the number of hours in which they are curtailed.

If export customers are allocated a portion of Shared Network Asset-related costs, it is Elenchus' view that export customers should also be allocated a portion of external revenues received by HONI for use of their assets. Elenchus recommends for full External Transmission Revenues to be allocated by the same methodology as Shared Network Asset-related costs.

The ETS rates that would result from applying these methodologies are provided in the following table using 2020 demand data and HONI's proposed 2023 revenue requirement:

Methodology	Allocator for Shared Network Asset-related costs		ETS Rate ($/MWh)
	Domestic Share	Export Share	
OEB 2020 Approved ETS rate			$1.85
2014 Report Methodology	Domestic 12CP	-	$1.67
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.07
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03

The cost allocation methodologies presented in this report to calculate the ETS rate are based on the following considerations:

- Direction from the OEB to HONI to review the allocation of Shared Network Asset-related costs to exports
- OEB report on Pole Attachment Charges
- Elenchus jurisdictional review of cost allocation methodologies
- IESO treatment of exports
- Export service curtailment in the last few years and expected curtailment in the near future

Elenchus views the cost allocation methodology presented in the May 2014 report and each of the methodologies identified in this report as being cost-based.

The May 2014 methodology was based on how the transmission system is designed and, since export needs are not considered in the planning of the transmission system, exports were not allocated a portion of Shared Network Asset-related costs.

The methodologies identified in this report reflect exports' use of the transmission system and how they are being treated by the IESO with not much service interruptions. Exports use the transmission system almost as much as domestic customers use the system, therefore, a reasonable basis exists for allocating a portion of Shared Network Asset-related costs to exports.

As in the May 2014 suggested methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS rate be adjusted to include other transmitters' approved revenue requirement.

While this report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, Elenchus' view is that whether or not the OEB should change ETS rates to reflect those network costs is a broader policy question for the OEB to determine.

1 INTRODUCTION

Hydro One Networks Inc. ("HONI") retained Michael Roger and Andrew Blair of Elenchus Research Associates Inc. ("Elenchus") in order to supplement the May 2014 cost-based methodology to establish the Export Transmission Service ("ETS") rate in Ontario, by identifying cost-based methodologies for allocating Shared Network Asset-related costs to exporters and which includes different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled.

The cost-based methodologies that have been identified in this report are intended to inform the OEB's decision-making on ETS rates going forward.

In its Decision and Order in HONI's most recent Transmission rate application, dated April 23, 2020 (EB-2019-0082), with respect to Export Transmission Service rates the Ontario Energy Board ("OEB") directed HONI to undertake further work on developing a cost-based ETS rate.

More specifically, the OEB stated on page 180 of its Decision and Order:

> *"Hydro One supported intervenor arguments that a cost allocation methodology that includes the allocation of shared network costs to exporters should be provided in Hydro One's next transmission rebasing application. The OEB agrees. This study should include different scenarios to take into consideration the fact that exporters do not receive the same priority access as domestic service until they are scheduled. The OEB agrees with the OEB panel for the ETS Decision that export service should continue to be viewed as a separate class. This study should be filed with Hydro One's next transmission rebasing application."*

This report presents the results of the review undertaken by Elenchus to establish potential cost-based allocation methodologies that allocate Shared Network Asset-related costs to export customers.

This report is divided into 8 main sections. Section 2 provides a background on the 2014 cost-based methodology previously developed by Elenchus to calculate an ETS rate, section 3 presents the principles of cost allocation and describes the previously developed cost-based methodology, section 4 describes the characteristics of the export class in Ontario, section 5 presents the results of Elenchus' survey of Export and Curtailable Transmission Rate-setting in other jurisdictions, section 6 describes three cost allocation methodologies that allocate Shared Network Asset-related costs to export customers, section 7 presents the results of these methodologies using 2020 data and section 8 provides conclusions. Appendix A contains the CVs for Michael Roger and Andrew Blair.

Michael Roger has been an expert dealing with cost allocation, rate design and rate regulation issues for over 40 years. Michael worked for over 32 years at Ontario Hydro, Ontario Power Generation and Hydro One and spent most of his career dealing with Cost Allocation and Rate Design issues for wholesale and retail electricity customers in Ontario. Since 2010, Michael has been an associate consultant at Elenchus. He has testified on numerous occasions at OEB proceedings and at proceedings across Canada on behalf of regulators, utilities and other stakeholders and also has provided expert advice to the OEB in various task forces dealing with cost allocation and rate design issues. Michael's vast experience with Cost Allocation issues was applied in reviewing and modifying the cost-based cost allocation methodology to calculate the ETS rate and forms the basis for Elenchus recommended methodology to the OEB.

Andrew has worked as a research analyst with Elenchus for five years. He has experience contributing to Elenchus reports on cost allocation and rate design matters in Ontario and other jurisdictions across Canada.

2 BACKGROUND

2.1 SUMMARY OF 2014 REPORT

In its May 2014 Report Elenchus proposed a cost allocation methodology to determine the ETS rate that was based on cost causality, was simple and followed the traditional three steps of a cost allocation methodology.

The assumptions used in developing the May 2014 methodology were that:

- Export is only served when there is spare capacity available,

- Generators and importers in Ontario do not pay for the use of the Transmission System,
- HONI's planning of the Network transmission system does not take into consideration the capacity needs of export customers,
- Export is treated as "Interruptible" for cost allocation purposes.

The May 2014 methodology main characteristics were that:

- Only dedicated Export Network Assets were allocated to Export,
- Export is considered to be "Interruptible", therefore no Shared Network Asset-related costs are allocated to Export,
- Shared Network OM&A Costs are allocated to Export, and
- 12 Coincident Peak (CP) is used as the allocator

Additionally, the May 2014 methodology:

- Used prior year actual hourly data for domestic and export customers,
- Used the 12 CP allocator in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared OM&A costs,
- Allocated only the rate base cost of dedicated assets that are used to serve export customers and the related costs to the export customer class,
- Allocated OM&A costs related to the use of shared assets to export customers using composite assets as the allocator,
- Allocated no external revenues to the export customer class,
- Based the ETS rate on HONI's OEB approved Network revenue requirement in determining the Uniform Transmission Rates, adjusted to include other transmitters' approved revenue requirement.

2.2 OEB DECISION EB-2019-0082

The OEB in its Decision and Order in Proceeding EB-2019-0082, page 180, provided the following reasoning in support of its decision, quoted above, directing HONI to do further work on the ETS rate cost allocation methodology:

"Shared network facilities have been paid for by domestic customers. The OEB has determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates. The OEB does see some similarity with the rate established for attachments to distribution poles by third parties such as telecommunications and cable companies, as noted by SEC. For pole attachments, the OEB adopted a hybrid methodology to allocate common costs. The OEB has insufficient information to conclude what the appropriate allocation of common network costs should be for exporters. This needs to take into consideration that while exporters make use of the network system, Hydro One does not plan its system for the benefit of exporters. However, at the oral hearing Hydro One testified that once scheduled, with the exception of an emergency or supply issue, exporters are treated as firm as domestic load."

2.3 Pole Attachment Rate Decision (EB-2015-0304)

In Proceeding EB-2015-0304 dealing with Wireline Pole Attachment Charges, the OEB in its report dated March 22, 2018 said on page 30:

> *"In regulatory economics and practice in most jurisdictions, it is uncontroversial that each attacher to the network will be responsible for the direct or incremental costs that the attachment drives. The question that the OEB must answer is how much of the common costs of the pole network will be assigned to the incumbent power utility owners and each party wishing to attach to ensure that a reasonable charge is established. In addition, **one must also consider the value that third party attachers obtain from leveraging an established network that spans the entire province**, (emphasis added)"*

On page 33 of the report the OEB concluded that:

> *"For these reasons, the OEB is of the view that the hybrid **equal sharing methodology is an efficient and fair cost allocation to be applied to third party attachers** (emphasis added). As noted previously, given that Ontario's vast network of more than 200,000 km of low voltage distribution lines provide tremendous value to third party attachers through an existing network, readily available for expansion, the **OEB will consider moving from a cost-based approach to a value-based approach** (emphasis added) as part of the Part II review."*

The above OEB report was taken into consideration by Elenchus in its review and development of cost-based methodologies for allocating Shared Network Asset-related costs to export customers.

3 MAY 2014 COST ALLOCATION METHODOLOGY

Elenchus' proposed May 2014 cost allocation methodology to determine the ETS rate was based on cost causality, was simple and followed the traditional three steps of a cost allocation methodology: functionalization, classification and allocation.

Elenchus looked at how transmission assets are being used to sell electricity, either to domestic customers or to neighbouring jurisdictions by exporters.

In Ontario, generators do not pay for the use of the transmission system when they inject power into the grid in order to supply domestic electricity needs. Elenchus applied this same principle when evaluating the interconnected assets with neighbouring jurisdictions used by exporters. The interconnected assets are used to both export and import power and since generators in Ontario do not pay for the use of the transmission assets and the ETS rate is not applied to power imported into Ontario, Elenchus assumed that importers would also continue to not be charged for the use of the transmission system.

The May 2014 methodology considered the sale of electricity to domestic customers and neighbouring jurisdictions, not how the electricity was sourced and made available to satisfy sales. It focused narrowly on cost drivers without considering other value drivers that can be relevant to designing equitable rates.

HONI's 2013 transmission assets and revenue requirements were used in developing the May 2014 approach.

The May 2014 cost allocation methodology to determine the ETS rate reflected the interruptible nature of exports. The basis for treating exports as interruptible loads was found in the OEB's Decision with Reason in proceeding EB-2012-0031 that on page 5 stated that:

> *"First, whether curtailments originate from generation issues or transmission issues, the Board agrees that export service does not receive the same priority access as*

domestic service. The Board accepts that the market rules treat exporters more as an interruptible load. This difference in treatment related to generation capacity has consequences for the overall service, even if export transmissions rights are technically as firm as domestic transmission rights. As a result, the Board finds that it may be appropriate for the export service to be viewed as a separate class."

3.1 FUNCTIONALIZATION

In consultation with HONI, Elenchus determined that the assets and costs associated with export activities can be found in the following HONI transmission asset functions:

- Network (500 kV, 230 kV, and 115 kV lines)
- Dual Function lines (Network portion)
- Generation Line Connection
- Generation Transformation Connection
- Common (telecommunication equipment, control centre)
- Other (facilities not allocated to other functions under normal operating conditions)

These functions included dedicated and shared assets, and related costs used by domestic and export customers.

The remaining functions used by HONI in determining its revenue requirement (e.g. transformation, line connection, line connection portion of dual function lines) were considered to be used only by domestic customers. Each function is divided into three categorizes:

- Dedicated to Domestic
- Dedicated to Interconnect
- Shared

External revenues were also considered in the development of the May 2014 cost allocation methodology. These revenues result mainly from secondary land use in right of ways and from providing maintenance services to other entities. These revenues are the result of using HONI's assets which have been designed to serve domestic customers only, therefore, no external revenues were allocated to export customers.

3.2 Classification

Generally in cost allocation, transmission assets and related costs are classified as demand related. Transmission assets are designed to meet the maximum demand imposed by users of the system. Based on the functions evaluated, it was determined that the assets and related costs considered in the development of the May 2014 ETS rate methodology were all demand related. There were no energy related or customer related assets and costs.

3.3 Allocation

In the cost allocation methodology developed to derive the ETS rate two customer classes were considered: domestic and export.

3.3.1 Assets Dedicated to Domestic

Assets dedicated to domestic customers are assets that only serve to connect HONI customers' load to the network. Assets, asset-related costs, OM&A, and external revenues dedicated to domestic are directly allocated to the Domestic class.

3.3.2 Assets Dedicated to Interconnect

Assets dedicated to interconnect are assets that only serve to connect to another transmission utility. The May 2014 report directly allocated the assets and costs dedicated to interconnect directly to the Export class. This report recommends a refinement to that methodology to include the contribution of imports in Section 6.2.

3.3.3 Shared

Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.

As export was considered to be interruptible service, no asset-related costs associated with shared assets, including depreciation, interest, return on equity and taxes, were allocated to the export customer class.

Under the strict cost driver approach, this methodology was considered appropriate because, as confirmed by HONI staff, HONI's planning of the Network transmission system does not take into consideration the capacity needed to supply export customers. Transmission planning is based only on the capacity needs of domestic customers.

The OM&A costs related to the use of shared assets were allocated between domestic and export customers using the allocators described below.

3.4 COINCIDENT PEAK ALLOCATOR

In cost allocation, the allocation of demand related assets that are closest to the customer are allocated based on the non-coincident demand of the customer. The required assets are sized reflecting the maximum customer electricity demand.

Further away from the customer and closer to the generation system, it is the aggregate electricity demand of all customers, and not the sum of the individual customer demands, that determines the size of the facilities required to satisfy customers' electricity needs. In cost allocation, when apportioning assets and costs further away from the customer (e.g. generation, transmission network) and closer to the generation of electricity, it is the coincident demand that is used as an allocator, reflecting the criteria used to size the required assets.

In Proceeding RP-1999-0044, the OEB reviewed allocators that could be used to recover Network assets and costs and recommended against the use of non-coincident peak and settled on the use of coincident peak. With respect to using 1 CP, in paragraph 3.4.27 of the OEB Decision it states that:

> *"A rate design aimed at customer demand reduction during the system's coincident peak hours would meet the test of economic efficiency, but only if the network transmission system is generally capacity-constrained. This is not the case for the OHNC [Hydro One] network transmission system either today or in the foreseeable future."*

12 CP continues to be used by HONI in apportioning assets and costs when allocating Dual Function Line assets (EB-2019-0082, Exhibit I1, Tab 1, Schedule 2, pages 5-7).

Coincident peak is the hourly demand of domestic and export customers at the hour of maximum demand in the Ontario electricity system.

1 CP is the demand for each customer class at the hour of maximum system demand in a year. 12 CP is the sum of the demand for each customer class at the hour of each month's maximum system demand.

1 CP or 12 CP are commonly used by utilities in cost allocation studies to apportion generation and transmission costs amongst customer classes.

Transmission system coincident peak data from 2011 to 2013, used in Elenchus's 2014 report, are provided below for reference. Updated values used to calculate ETS rates under the methodologies discussed in this report are provided in Section 6.2.1.

Table 1

Coincident peak 2011 to 2013

	2011			2012			2013		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	2,549	25,450	27,999	2,179	24,636	26,815	1,952	24,927	26,879
12CP	31,343	250,819	282,161	28,164	251,842	280,006	30,240	255,417	285,657

	2011 to 2013 Average		
	Export	Domestic	Total
1CP	2,227	25,004	27,231
12CP	29,916	252,692	282,608

The relative shares of 1CP and 12CP are used to derive the following allocators.

Table 2

Coincident peak %

	2013 Data			Average 2011 – 2013 Data		
Coincident Peak	**Total**	**Domestic**	**Export**	**Total**	**Domestic**	**Export**
1 cp	100.00	92.74	7.26	100.00	91.82	8.18
12 cp	100.00	89.41	10.59	100.00	89.41	10.59

Elenchus recommended in the May 2014 methodology that 12 CP be used to allocate shared assets between domestic and export customers using the last year for which information was available.

When system loads are relatively flat and do not show a pronounced yearly peak, 12 CP is usually used by utilities to allocate demand related assets and costs. In instances where there is a significant yearly peak compared to other peaks in the year, that is a very peaky load profile with low load factor, then 1 CP would more commonly be used to allocate demand related assets and costs.

As discussed further in Section 4.2, though Ontario's domestic peaks are generally in the summer months, high exports in the winter often cause the transmission system peak to occur in December and January. A 1 CP could vary considerably from year to year depending on the month the transmission system peak occurs. For example, the export class is responsible for 7.58% of the 2016 1CP, which occurs in September 2016, and 15.83% of the 2017 1CP occurring in December 2017. Using the 12 CP is considerably more consistent over time, and therefore continues to be the recommended allocator.

3.5 COMPOSITE ALLOCATORS

The asset functions identified were apportioned between domestic and export customers using the 12 CP allocator based on 2012 actual hourly data in order to develop composite allocators used to allocate shared OM&A costs to domestic and export customer classes in the May 2014 methodology. Table 3 below includes the composite allocators used in the May 2014 methodology.

Table 3

Net Fixed Assets

	Total	Domestic	Export
2014 Report	**100.00%**	92.89%	7.11%

The OM&A costs related to the identified shared functions were allocated in the May 2014 cost allocation methodology to domestic and export customers using Net Fixed Assets as composite allocators.

4 CHARACTERISTICS OF HONI'S EXPORT TRANSMISSION CLASS

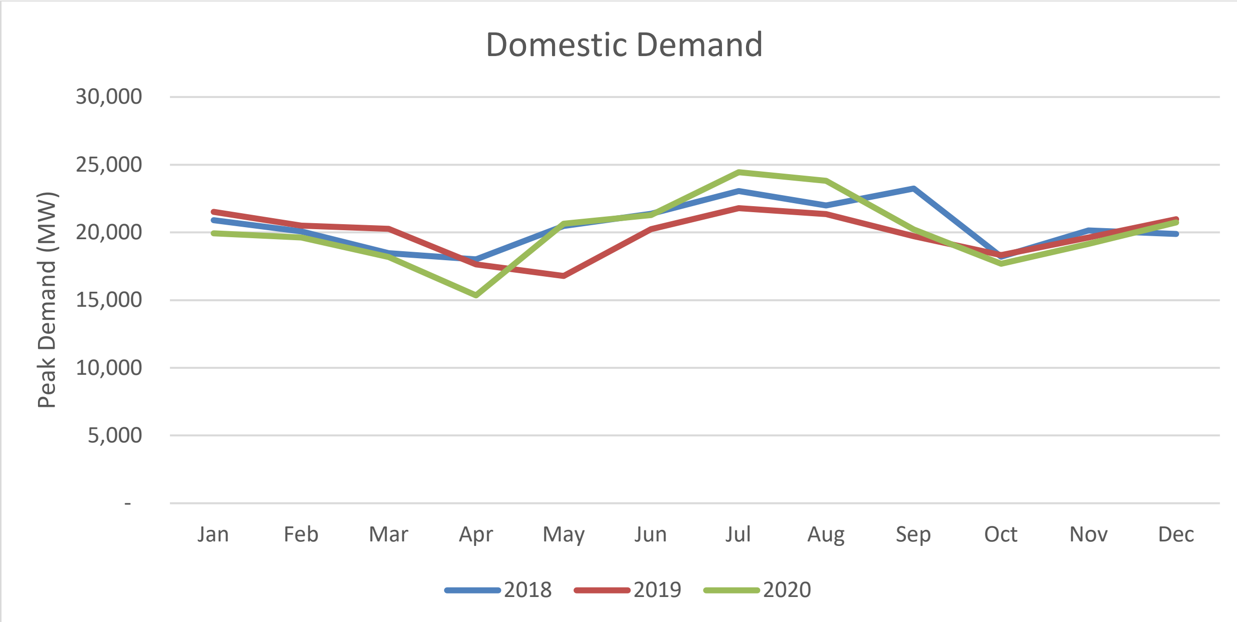
4.1 EXPORT TREATMENT BY IESO

Elenchus discussed with the IESO how exports are being treated in Ontario. The IESO provided the following explanations:

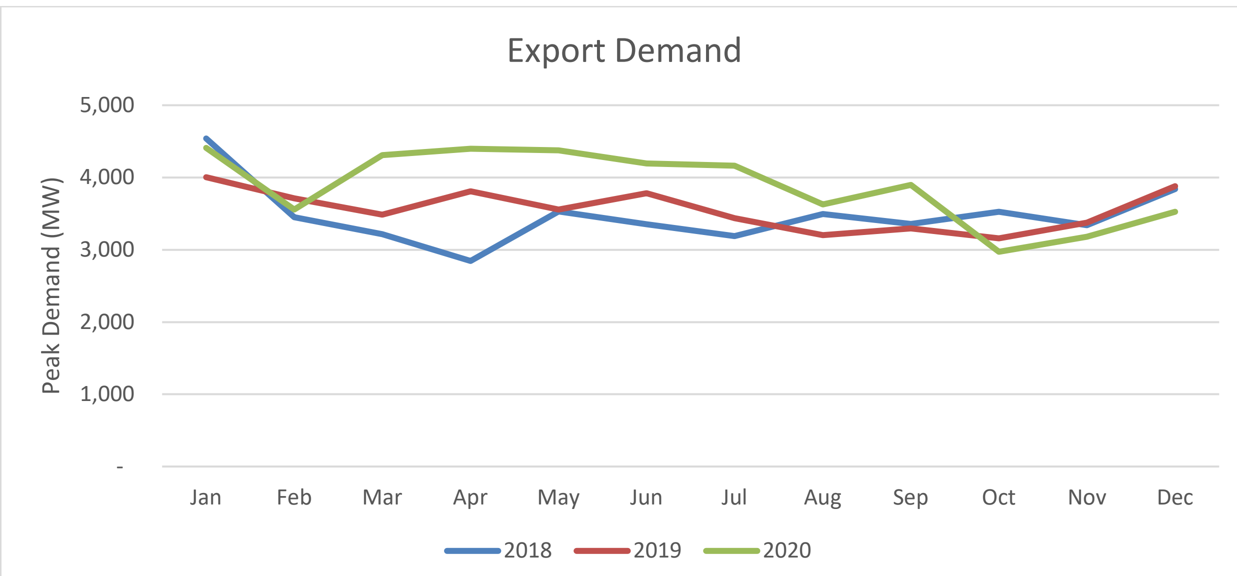
> *The IESO provides market participants and consumers (including exporters and domestic loads) with the same access to service. This is consistent with requirements of Section 1(e) of the Electricity Act, 1998:*
>
> > *(e) to provide generators, retailers, market participants and consumers with non-discriminatory access to transmission and distribution systems in Ontario*
>
> *While exports do receive the same access as domestic loads, exports are subject to more frequent interruption in service compared with domestic load. From a planning perspective, the IESO treats loads differently than exports. In contrast to domestic load, the IESO does not factor exports into its reliability planning assessments. This means that the IESO does not procure generation or transmission assets to serve future export demand.*

4.2 DOMESTIC AND EXPORT DEMAND PROFILES

Ontario is a summer-peaking province, with peak demands generally occurring in the summer months and smaller peaks occurring in winter months. However, in some recent years the domestic peak occurred in September.



Export demand peaks in the winter months as shown in the graph below.



The following table shows Domestic, Export, and Total Transmission System peaks over the past 10 years, along with the months in which the peak occurs.

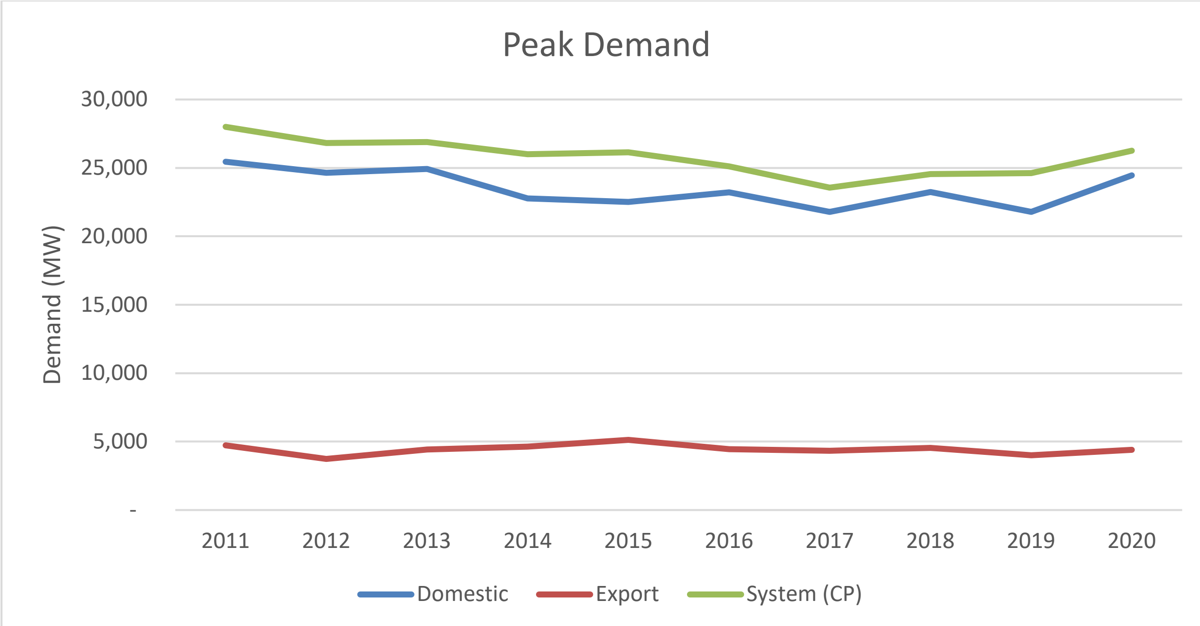
Table 4

Peak Demands 2011-2020

	Domestic		Export		System (1CP)	
	Peak	Month	Peak	Month	Peak	Month
2011	25,450	July	4,736	January	27,999	July
2012	24,636	July	3,735	January	26,815	July
2013	24,927	July	4,417	January	26,879	July
2014	22,774	January	4,629	January	26,012	January
2015	22,516	July	5,127	February	26,151	January
2016	23,213	September	4,438	January	25,118	September
2017	21,786	September	4,320	December	23,558	December
2018	23,240	September	4,540	January	24,550	January
2019	21,791	July	4,004	January	24,613	July
2020	24,446	July	4,410	January	26,258	July

From 2011 to 2013, the years analysed for Elenchus' 2014 ETS Report, the transmission system peak was in July, driven by domestic demands. In the following seven years, four of the transmission system peaks have occurred in December or January, driven by higher export demands.

Peak demands have declined in recent years. The average transmission system peak demand declined by 7.3% from the 2011 to 2015 period to the 2016 to 2020 period. The following chart displays domestic, export, and system peak demands from 2011 to 2020.



Domestic consumption volumes have declined and Export volumes have increased over the same period.

Table 5

Consumption 2011-2020

	Domestic MWh	Export MWh	Total MWh
2011	141,473,805	12,848,505	154,322,310
2012	141,287,009	14,627,403	155,914,412
2013	140,736,784	18,309,407	159,046,191
2014	139,803,825	19,073,299	158,877,124
2015	137,011,780	22,618,058	159,629,838
2016	136,989,747	21,858,101	158,847,848
2017	132,090,992	19,097,894	151,188,886
2018	137,436,546	18,590,935	156,025,737
2019	135,162,188	19,796,035	154,958,223
2020	132,225,424	20,377,407	152,602,831

Average domestic volumes have declined by 3.8% from the 2011 to 2015 period to the 2016 to 2020 period, whereas average export volumes have increased by 14% between the same periods.

4.3 CURTAILMENTS

The IESO considers exporters to be a "curtailable" rather than "interruptible" class, consistent with the North American Reliability Council (NERC) definition of interruptible.

As domestic peak demands have declined in recent years, the approximate number of hours when exports curtailments were active have also fallen.

Table 6

Year	Hours with Export Curtailment
2016	35%
2017	33%
2018	28%
2019	22%
2020 (until October)	18%

With respect to potential curtailments that exports may be subjected to, the IESO provided the following explanation:

> *"Exports are subject to materially different treatment from domestic load in several ways and as a result are curtailed more frequently than internal load. The IESO does not factor exports into its reliability planning assessments, which means it does not procure generation or transmission assets to serve export demand. Also, compared to domestic load, there are more reasons that export transactions could be subject to curtailment. Exports can be curtailed due to internal and external transmission security and adequacy reasons. As a result, the IESO curtails exports for reliability reasons more often than domestic load. In the first ten months of 2020, the IESO curtailed exports in approximately 18% of all hours to manage reliability.*

To provide an indication of the degree to which exports are curtailed at peak times, the IESO provided the following:

> *Over the top 5 peak hours over the last 5 years, the IESO curtailed exports in 11 out of 25 hours. The average quantity of exports curtailed was 158MW or approximately 10% of exports scheduled.*

5 Export and Curtailable Transmission Rate-setting in Other Jurisdictions

Elenchus researched transmission rate-setting processes in jurisdictions across Canada and the United States. Transmission rate-setting in Ontario differs considerably from the processes used in other jurisdictions. Elenchus did not find any jurisdictions in which cost allocation principles are used for the purpose of allocating shared network costs between domestic and export classes. Furthermore, cost allocation principles are not used to determine differential firm and non-firm charges.

5.1 Open Access Transmission Tariff

The majority of jurisdictions surveyed by Elenchus, including all Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) in the United States and most ISOs and transmitters in Canada set Open Access Transmission Tariffs (OATTs) in accordance with FERC Orders No. 888, 889, 890, and 2000. All Canadian provinces operate within the OATT framework except Ontario and Alberta.

These jurisdictions have postage stamp "Network Service charges" that are analogous to Ontario's domestic transmission tariff. Exports are analogous to "Point-to-Point" transmission service, which are applied to the transmission of energy along specific paths, from a point of receipt to a point of delivery. Unlike Ontario's Domestic and Export rates, which are set based on an allocation basis, Point-to-Point charges are calculated[3] based on the Network Service charge.

5.2 Interruptible vs. Non-Firm

Point-to-Point service can be firm or non-firm. Firm service is offered only if the remaining transmission capacity is sufficient to provide that service.

[3] Point-to-Point charges may be equal to Network Service charges, or otherwise calculated with the same revenue requirements and billing determinants.

Transmission service that can be curtailed is classified as "Non-Firm" rather than interruptible. The same charges apply to both Firm and Non-Firm customers.

In practice, Firm Point-to-Point service customers schedule short-term capacity when it is available. Non-Firm Point-to-Point service have lower priority, and therefore a higher chance of being curtailed, but service scheduling is more flexible. Firm Service is provided for periods ranges of one year to one day and can be scheduled the day prior to service (generally by 10:00 am). Non-Firm service can be scheduled up to one day at 2:00pm prior to service for periods of one hour to one month. Point-to-point service may also be subject to discounted prices as long as they are submitted on the OASIS and available to all customers on a non-discriminatory basis.[4]

5.3 CAPACITY-BASED CHARGES ($/kW)

Most jurisdictions surveyed apply capacity-based service charges for both Network and Point-to-Point services.[5] The service charges can be considered reserved demand charges as charges are applied based on the capacity that is reserved during scheduling, regardless of the actual capacity utilized. By FERC Order No. 890, Annual charges are calculated based on the combined revenue requirements of transmitters within an RTO or ISO, divided by the system capacity and monthly charges are derived as one twelfth of the annual charge. Weekly, daily, and hourly charges are typically derived by RTO/ISOs from the annual service charge by the calculations provided in Table 7.

[4] Discounts are typically offered in times that there is excess transmission system capacity. Discounts may be priced dynamically to maximize revenues or may be set according to a defined policy, such as reducing prices to off-peak rates in nominally on-peak periods. Discounts may be offered on specific paths or points of departure.

[5] NYISO is an exception. Energy-based ($/kWh) charges apply to Point-to-point service.

Table 7

Charge	Methodology
Annual Charge	$\frac{\text{Revenue Requirement}}{\text{Total Capacity}}$
Monthly Charge	1/12 of Annual Charge
Weekly Charge	1/52 of Annual Charge
Daily On-Peak Charge	1/5 of Weekly Charge
Daily Off-Peak Charge	1/7 of Weekly Charge
Hourly On-Peak Charge	1/16 of Daily On-Peak Charge
Hourly Off-Peak Charge	1/24 of Daily Off-Peak Charge

The same charges apply to Network and Point-to-Point service and Firm and non-Firm service. Hourly charges are only available for Non-Firm service and not all jurisdictions have separate Off-Peak and On-Peak charges.

5.4 ALBERTA

The transmission charges applicable to exporters in Alberta are established in the Alberta Electricity System Operator ("AESO") tariff proceedings before the Alberta Utilities Commission ("AUC"). The AESO is responsible for collecting the transmission revenue requirements of Alberta's transmitters.

The principal transmission charge is the Demand Transmission Service rate ("Rate DTS"). Rate DTS incudes a capacity charge and a consumption charge. Other rates, including the Demand Opportunity Service rate ("Rate DOS"), Export Opportunity Service Rate ("Rate XOS"), and Export Opportunity Merchant Service rate ("Rate XOM"), are derived based on Rate DTS.

Demand Opportunity Service is interruptible, temporary, and available only when there is surplus transmission capacity. There are three rates: service in 7-minute increments, service in hour increments, or service for longer than 8 hours. Rates are charged based on consumption and differ significantly between the three types of service.

Export Opportunity Service and Export Opportunity Merchant Service applies to exporters. Nominally the export service differs based on the year the intertie was put in service, however, there is no difference in the rate charged.

For each tariff proceeding the AESO conducts a cost allocation study which allocates costs to Rate DTS and Supply Transmission Service rate ("Rate STS"). Costs related to loses and generation connections are allocated to Rate STS and the remainder is allocated to Rate DTS. The Rate DTS revenue requirement is functionalized to the following components: Bulk System, Regional System, Point of Delivery, Operating Reserve, Voltage Control, and Other System Support and classified as either fixed-based or usage-based. Bulk System and Regional System are analogous to the Shared Network function within HONI's ETS model.

The DTS functions are classified between capacity and energy. The classified functions are then each divided by the energy forecast to provide the DTS rate by its components. Export rates are calculated as a subset of the DTS rate components, some of which are pro-rated. The export rate is comprised of 100% of the energy-classified Bulk System and Regional System rates that are applicable to the DTS rate, 20% of the capacity-classified Bulk System and Regional System rates and 32% of the Operating Reserve rate. The export rate does not receive a share of Point of Delivery, Voltage Control, or Other System Support rate components.

The AESO provided the following rational for applying 20% to capacity-related Bulk and Network System costs: "The 20% contribution represents a minimal amount as Rate XOS includes no contract capacity or ratchet-based charges in hours in which XOS 1 Hour interchange transactions are not scheduled."[6] The AUC has accepted this methodology in subsequent tariff applications.

The total revenue from the export rate is grouped with other revenue offsets to reduce the total DTS revenue requirement. The revenue is not used to offset the specific functions for which the export rate is attributed costs. For example, Point of Delivery costs are not attributed to the export rate but export revenue is used, in part, to reduce the Point of

[6] AESO Response to information request, AESO 2010 ISO Tariff Application (AUC.AESO-008)

Delivery component of the revenue requirement. Elenchus does not consider the manner that AESO sets export rates to be underpinned by a cost allocation methodology.

6 COST ALLOCATION METHODOLOGY OPTIONS

Elenchus reviewed the May 2014 cost-based methodology to calculate the ETS rate, held discussions with the IESO on how exports are treated in Ontario, reviewed the OEB report on Pole Attachment Charges and the OEB Decision and Order on HONI's transmission application (EB-2019-0082) and surveyed how export rates are set in other jurisdictions.

Based on the review conducted by Elenchus, this report presents cost-based methodologies that allocate Shared Network Asset-related costs to export customers.

Based on the information provided by the IESO on how exports are treated compared to domestic customers, exporters are able to use the transmission assets in the same manner as domestic customers unless they are curtailed by the IESO. Exports are subject to more service interruption than domestic customers. In the past few years, exports have been affected by fewer and fewer service interruptions and in 2019 and 2020 curtailments of some portion of export demand were close to 20% of the hours.

At times of the transmission system peak, exporters are able to use the transmission system. The IESO provided Elenchus with the information that:

> *"Over the top 5 peak hours over the last 5 years, the IESO curtailed exports in 11 out of 25 hours. The average quantity of exports curtailed was 158MW or approximately 10% of exports scheduled. "*

6.1 "NO FREE RIDERS" PRINCIPLE

As stated by the OEB in its report on Pole Attachment Charges, when developing a cost-based methodology, consideration can also be given to the value that users obtain from leveraging an established network. This means that there should not be users of a shared network that do not pay their fair share of costs for use of the shared network, also referred to as "free riders".

This principle is not unique to the OEB. For example, the Régie de l'énergie in Quebec has a long-standing "no free service"[7] guiding principle for cost allocation and rate design. FERC Order No. 1000 states as its first cost allocation principle that "costs should be allocated in a way that is roughly commensurate with benefits".[8]

6.2 COST ALLOCATION METHODOLOGY FOR ASSETS DEDICATED TO INTERCONNECT

Assets dedicated to interconnect serve both exports and imports. The May 2014 methodology recommended allocating all assets and costs for functions dedicated to interconnect to the Export class because importers do not pay for the use of the transmission system.

Since importers also use interconnection assets not all asset-related costs and OM&A related to interconnection should be directly allocated only to the Export class. Energy is imported to serve domestic load therefore a portion of interconnection assets, asset-related costs, and OM&A should be allocated to the Domestic class. Elenchus recommends that the intertie 12CP be used to allocate Dedicated to Interconnect assets and costs to the Export and Domestic classes. The intertie 12CP is derived in Table 8.

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[7] *"l'absence de service gratuity"* - For example, see Régie Decisions D-429 and D-97-47. Elenchus discussed this principle in its *Report on Énergir's Cost Allocation and Pricing of Gas Supply, Transportation and Load Balancing Services and Supply of Interruptible Service* (R-3867-2013A-0219*)*
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[8] FERC Order No. 1000 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities* addresses cost allocation with respect to new transmission facilities

Table 8

Intertie Coincident peak 2018 to 2020

	2018			2019			2020		
	Export	Import	Total	Export	Import	Total	Export	Import	Total
1CP	4,343	2,519	6,862	3,556	1,589	5,145	3,485	2,159	5,644
12CP	35,099	21,110	56,209	35,779	18,806	54,585	39,117	15,430	54,547

	2018 to 2020 Average		
	Export	Import	Total
1CP	3,795	2,089	5,884
12CP	36,665	18,449	55,114

The intertie 1 CP and 12 CP percentage allocators using 2018 to 2020 data are shown in the table below.

Table 9

Intertie Coincident peak %

	2020 Data			Average 2018 – 2020 Data		
Coincident Peak	Export	Import	Total	Export	Import	Total
1CP	61.75	38.25	100.00	64.49	35.51	100.00
12CP	71.71	28.29	100.00	66.53	33.47	100.00

Elenchus proposes to allocate assets and expenses that are categorized as Dedicated to Interconnect by the Intertie 12CP between Domestic and Export class.

6.3 COST ALLOCATION METHODOLOGY FOR SHARED NETWORK ASSETS

Since exporters are able to use the transmission system unless they are curtailed by the IESO, even at the times of the Ontario transmission system peak, Shared Network Asset-related costs can be allocated to export customers based on the cost causality principle. Elenchus' suggested allocator is based on data from peak periods, including peak periods in which export customers are curtailed. When they are curtailed, export peak volumes are reduced which is reflected in the suggested allocator and results in a reduction in the portion of costs allocated to exports.

Even though export demand needs are not taken into account when HONI designs the transmission system and the IESO does not factor exports into its reliability planning assessments, the fact that exporters can use the transmission system much of the time, including during peak periods, would support the allocation of Shared Network Asset-related costs to export customers.

6.3.1 ALLOCATORS

The data used in the May 2014 methodology were updated by Elenchus to reflect more up to date information. The demand imposed on the transmission system by both domestic and export customers is available from the IESO on an hourly basis. Elenchus recommends that the same allocators be used in the three identified methodologies.

Using 2018, 2019 and 2020 actual hourly load data for domestic and export customers from the IESO, transmission system coincident peak ("CP") allocators were developed.

Table 10
Transmission System Coincident peak 2018 to 2020

	2018			2019			2020		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
1CP	4,121	20,429	24,550	2,822	21,791	24,613	2,583	23,675	26,258
12CP	25,336	241,536	266,872	27,510	237,055	264,565	28,428	237,606	266,034

	2018 to 2020 Average		
	Export	Domestic	Total
1CP	3,175	21,965	25,140
12CP	27,487	238,507	265,994

The 1 CP and 12 CP percentage allocators using 2018 to 2020 data are shown in the table below:

Table 11

Coincident Peak %

	2020 Data			Average 2018 – 2020 Data		
Coincident Peak	**Export**	**Domestic**	**Total**	**Export**	**Domestic**	**Total**
1 cp	9.84	90.16	100.00	12.63	87.37	100.00
12 cp	10.69	89.31	100.00	10.33	89.67	100.00

Table 12 includes the percentage allocation of the composite allocators to the two customer classes based on 12 CP using 2020 data.

Table 12

Allocators using 2020 Actual Hourly Data

Allocator	Basis	Export	Domestic	Total
Shared Net Fixed Assets	Transmission System 12CP	10.69%	89.31%	100.00%
Dedicated to Domestic	Direct Allocation	0.00%	100.00%	100.00%
Dedicated to Interconnect	Intertie 12CP	71.71%	21.29%	100.00%

6.3.2 SHARED NETWORK ASSETS

The cost allocation methodology recommended in Elenchus' May 2014 report, which informed the setting of the current ETS rate, was to allocate Shared Network Asset OM&A between the Domestic and Export classes by the Net Fixed Assets allocator. Depreciation expense, return on capital, and PILs[9] related to Shared Network Assets were allocated fully to the Domestic class.

If Shared Network Asset-related costs are to be allocated, one of Elenchus' suggested methodologies is for Shared Network Asset-related costs to be allocated using the Shared Net Fixed Assets allocator (12CP). Assets Dedicated to Domestic and Dedicated to Interconnect would be excluded. To the extent that export customers are curtailed, the

[9] HONI is now subject to income taxes and not PILs following its IPO

export hourly data that is used as an allocator will reflect the impact of service interruptions.

Using Shared Net Fixed Assets as an allocator for Shared Network Asset-related costs between domestic and export customers will reflect each customer group's use of the transmission system, including the impact of service curtailment to export customers.

The other two methodologies adjust the 12CP by 50% reflecting the hybrid model and 20% reflecting the curtailment percentage model. The three Net Fixed Asset allocators are provided in the following table.

Table 13
Shared Network Asset Allocation Methodologies

	Net Fixed Assets			Hybrid Model			Curtailment % Model		
	Export	Domestic	Total	Export	Domestic	Total	Export	Domestic	Total
12CP	28,428	237,606	266,034	22,742	237,606	260,348	14,214	237,606	251,820
%	10.69%	89.31%	100.00%	8.74%	91.26%	100.00%	5.64%	94.36%	100.00%

6.3.3 External Revenues from Shared Network Assets

If export customers are allocated a portion of Shared Network Asset-related costs, it is reasonable that export customers should also be allocated a portion of external revenues received by HONI related to the use of those assets. The allocator suggested by Elenchus for full External Transmission Revenues is the same allocator recommended for Shared Network Asset-related costs, which is Shared Net Fixed Assets.

6.3.4 Deferral and Variance Account Balances

HONI's Rates Revenue Requirement includes deferral and variance account balances. Aside from the Excess Export Service Revenue Variance Account, the accounts are generally not attributable to either Domestic or Export customers or the specific assets used by each customer group, so it is appropriate to allocate these balances to the Export class. The sum of HONI's deferral and variance account balances, excluding Excess

Export Revenues, are allocated based on each class's share of the Revenue Requirement.

7 ETS RATE RESULTS

7.1 METHODOLOGIES CONSIDERED

The following cost-based methodologies were considered by Elenchus to be appropriate options to allocate Shared Network Asset-related costs to export customers:

- Fully allocate Shared Network Asset-related costs on the basis of Shared Net Fixed Assets.
- Apply an adjusted Shared Net Fixed Assets allocator with export 12CP discounted by 50%, as a proxy for a hybrid model, half-way between no allocation and full allocation of Shared Network Asset-related costs to exports.
- Apply an adjusted Shared Net Fixed Assets allocator with a percentage of export demand discounted based on the service curtailment that affected exports in the last few years. Assuming that exports were curtailed 20% of the hours in the last few years, adjust export volumes to 80%.

The results of these methodologies are provided in the following table using 2020 data[10]:

Table 14

Methodology	Allocator for Shared Network Asset-related costs		ETS Rate ($/MWh)
	Domestic Share	Export Share	
OEB 2020 Approved ETS rate			$1.85
2014 Report Methodology	Domestic 12CP	-	$1.67
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.06
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.40
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.03

As in the May 2014 suggested methodology, Elenchus suggests that the three proposed methodologies in this report to calculate an ETS rate be adjusted to include other transmitters' approved revenue requirement. The adjusted ETS rates under the proposed methodologies is provided in Table 15.[11]

Table 15

Adjusted ETS Rates

Methodology	Allocator for Shared Network Asset-related costs		Adjusted ETS Rate ($/MWh)
	Domestic Share	Export Share	
Allocation on Basis of 100% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP	$6.54
Allocation on Basis of 50% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 50%	$3.66
Allocation on Basis of 80% of Shared Net Fixed Assets	Domestic 12CP	Export 12CP * 80%	$5.42

[10] HONI's 2023 revenue requirement and actual 2020 load and consumption data

[11] Rates are adjusted by 7.77%, calculated as the sum of HONI's 2023 Network Revenue Requirement and the Network Revenue Requirements of all other transmitters (as per EB-2020-0251) divided by HONI's 2023 Network Revenue Requirement.

8 CONCLUSIONS

Elenchus has identified cost allocation methodologies that allocate Shared Network Asset-related costs to export customers for the purpose of informing the OEB's decision-making on ETS rates going forward. Our analysis has taken the following into consideration:

- Direction from the OEB to HONI to review the allocation of Shared Network Asset-related costs to export
- OEB report on Pole Attachment charges
- Elenchus jurisdictional review of cost allocation methodologies
- IESO treatment of export
- Export service curtailment in the last few years and expected curtailment in the near future

Elenchus views each cost allocation methodology, including the May 2014 approach and the methodologies included in this report, as being cost-based. The changes arise from the inclusion of "no free service" as an appropriate principle to adopt in addition to the strict cost causality principle.

The May 2014 methodology was based on how the transmission system is designed and since exports needs are not considered in the planning of the transmission system, exports would not be allocated a portion of Shared Network Assets.

The methodologies identified in this report account for how exports are being treated by the IESO. Exports use the transmission system almost as much as domestic customers use the system, including at peak times, therefore, exports could be allocated a portion of Shared Network Asset-related costs. If exports are to be allocated a portion of Shared Network Asset-related costs, Elenchus is of the view that exports should also then be allocated a portion of External Transmission Revenues received by HONI.

While this report presents options for allocating Shared Network Asset-related costs to exports on a cost causality basis, Elenchus' view is that whether or not the OEB should change ETS rates to reflect those network costs is a policy question for the OEB to determine.

APPENDIX A - CVS

MICHAEL J. ROGER

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ASSOCIATE, RATES AND REGULATION

Michael has over 40 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**

Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies such as Working Capital Allowance and shared services studies. Prepare and defend related evidence. Appear as expert witness at regulatory proceedings.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Ontario Power Generation, Veridian, SaskPower, British Columbia Utilities Commission and APPrO.

Hydro One Networks Inc. **2002 - 2010**

Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.
- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.

- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**

Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**

Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.

- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

ANDREW BLAIR

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RESEARCH ANALYST

Andrew Blair joined Elenchus in January 2016 as a research analyst. He previously worked for the Ontario provincial government over a seven-year period as a trust analyst and a trust accountant. Andrew has a Master's Degree in Economics from Carleton University and a Bachelor's Degree in Economics and Financial Management from Wilfrid Laurier University.

PROFESSIONAL OVERVIEW

Elenchus Research Associates **January 2016 - Present**

Research Analyst

- Consulting in the areas of cost allocation modeling and load forecasting
- Provide research and modeling support for economic feasibility studies
- Support existing Elenchus applications, such as RateMaker
- Research background information related to regulatory filings
- Prepare cross-examination documents for regulatory hearings
- Design and monitor content for new forward-looking electricity-focused information service

Office of the Public Guardian and Trustee **May 2012 – June 2013**

Trust Analyst **Summers 2010 & 2011**

- Designed estate allocation and payment disbursement system
- Summarized and analyzed aggregate account information
- Allocated interest and fees to close out accounts
- Researched Public Guardian clients' files and family histories to determine estate beneficiaries
- Located beneficiaries and distributed estates

Accountant of the Superior Court of Justice **Co-op Student 2006**

Trust Accounting Officer **Summers 2007 - 2009**

- Reconciled client account balances
- Located clients with an outstanding balance with the court
- Updated client account balances as well as pension and disability allowances

ACADEMIC ACHIEVEMENTS

June 2014	Master of Arts, Economics, Carleton University
June 2012	Bachelor of Arts, Economics and Financial Management, Wilfrid Laurier University

Prepared for:

Hydro One Networks Inc.

Jurisdictional Review of Export Transmission Service (ETS) Rates Study

Final Report

Prepared by:

Charles River Associates

200 Clarendon Street

Boston, Massachusetts 02116

Date: March 29, 2021

CRA Project No. 32328

Disclaimer

Table of contents

1. Executive Summary

1.1. Background and Scope of Study

A May 16, 2012 report by Charles River Associates (CRA) entitled "Export Transmission Service Tariff Study - Review of Rates in Neighboring Markets" (the "2012 Jurisdictional Review") was prepared for the Independent Electricity System Operator (IESO) in response to the Ontario Energy Board's (Board) decision in proceeding EB-2010-0002. The Board at that time had directed the IESO to undertake a comprehensive study to identify a range of proposed Export Transmission Service (ETS) tariffs, and their advantages and disadvantages. The 2012 Jurisdictional Review was to support modeling of export transactions with each neighboring market for identified ETS tariff structure/rate and would provide comparable data for the assessment of the proposed rates/rate structures for consistency with rates/rate structures in adjacent markets.[1] To that end, the 2012 Jurisdictional Review reviewed the export transmission tariff designs and rates in the electricity markets adjacent to Ontario and well as certain other U.S. markets as part of an evaluation of potential export tariff rates and structures.[2]

The Board in its Decision and Order on Hydro One's most recent transmission rate application (EB-2019-0082) ordered Hydro One to provide an updated jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications.[3] Torys LLP (Torys) as legal counsel on behalf of Hydro One Networks Inc. (Hydro One), retained CRA to update the 2012 Jurisdictional Review to reflect current export transmission service rates in other jurisdictions, the rationale behind those rates and how market implications are considered in the setting of export transmission service rates in those jurisdictions. Torys and Hydro One also requested that CRA consider whether any additional electricity market jurisdictions, including Canadian jurisdictions, should be added to the 6 jurisdictions considered in the 2012 Jurisdictional Review and if so, to include these additional jurisdictions in CRA's work.

This Study (Study) therefore is an update to the 2012 Jurisdictional Review, and reports on the current (2020) ETS rates for the jurisdictions included. In addition, where suitable information is available, this Study describes the regulatory rationale supporting the ETS rates in those jurisdictions.

CRA's research methodology was to: 1) identify the applicable tariffed service and rate for generation export service in each jurisdiction; 2) obtain the applicable posted Open Access Transmission Tariff (OATT) from each market operator's website; 3) review the relevant tariff and confirm applicable rates and services for exports; and 4) conduct telephonic discussions with market operator staff where needed to confirm applicable tariff services and rates for exports. To conduct our research for regulatory rationale, CRA conducted extensive research on applicable regulatory commission websites such as the Federal Energy Regulatory

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1 See 2012 Jurisdictional Review, page 5.

2 The 2012 Jurisdictional Review included the following jurisdictions: MidContinent ISO (MISO), PJM, New York ISO (NYISO) and TransÉnergie (Québec). The rates provided in the 2012 ETS Review used C$1.0 = US $1.0117 conversion based on average rate during 2011; the conversion used for this update is C$1.0 = US $0.79 conversion as of January 2021.

3 See EB-2019-0082, Decision and Order dated April 23, 2020, page 180.

Commission (FERC) for U.S. jurisdictions, and applicable provincial commissions for Canadian jurisdictions to identify and obtain regulatory evidence where available; and, CRA reviewed regulatory evidence to evaluate rationale where information was available.

1.2. Findings Summary

Appendix A summarizes the 2020 rates in each jurisdiction for Firm and Non-Firm Point-to-Point (PTP) Export Transmission Services (ETS). Also shown for comparative purposes is the approved export tariff for Ontario. The rates are reported on an annual, monthly, weekly and daily basis, consistent with how they appear in the relevant tariff.

We observe that ETS rate levels in general have increased since 2012 and display no changes in rate design. The rate level change is attributable to inflation and transmission expansion since 2012. The regulatory rationale for rate design differs across markets studied. For certain established U.S. jurisdictions including ISO-NE, NYISO, PJM, and MISO, the OATT and rates currently in place for transmission service, including service for exports, appear to have developed from principles affirmed by the FERC Order No. 888-A.[4] Current ETS rate design was “inherited” from the former power pools that were in place in those regions prior to ISO/RTO implementation. These rates are designed to recover the total annual transmission revenue requirement (ATRR) over the forecasted annual billing units (12 Coincident Peak (CP) or zonal peak demand, or another basis). In these cases, the rates for export service are designed to recover total ATRR and there is no specific rate design step applied to encourage a particular export market result. Other jurisdictions studied appear to rely on a variation to the above approach for each jurisdiction as described further in this report.

4 https://www.ferc.gov/industries-data/electric/industry-activities/open-access-transmission-tariff-oatt-reform/history-oatt-reform/order-no-888 In 1996, before the formation of ISOs, FERC Order No. 888 (“the Order”) directed transmission owners to establish a Pro Forma Open Access Transmission Tariff (OATT). The primary goal of the Order is to promote competitive and non-discriminatory transmission access. So long as transmission owners meet that directive, the Order does not mandate uniform OATT schedules. In fact, the Commission does not make blanket revisions to point-to-point service provisions in OATTs because there is “no distinction between different tiers of physical entitlements to the transmission system in an organized market environment.”

2. Export Transmission Service Rates

2.1. Additional Jurisdictions Included in 2020 Study Update

CRA evaluated whether additional jurisdictions should be included in the Study. Based upon our evaluation of current markets, we included three additional jurisdictions: California ISO (CAISO), Southwest Power Pool (SPP), and Alberta Electric System Operator (AESO). Our rationale for adding these is as follows:

- CAISO initiated operations of the Western Energy Imbalance Market (WEIM) in 2014 which provides the opportunity to make valuable observations as to how export pricing within an imbalance market could operate.
- SPP is an expanding ISO with a physical footprint in 14 US states and is increasingly integrated and exchanging power with other US jurisdictions.
- AESO –Alberta is key Canadian merchant market that has been active in evaluating export rates and can serve as a good comparator.

2.2. 2020 Rate Updates

Please refer to Table 1 – Summary of 2020 Rates for Export Transmission Service for updated 2020 ETS rate-level results. Note the results reported in this table are shown in CAD, converted for US jurisdictions, and native market currency for Canadian jurisdictions.[5] As a comparison, Table 2 shows a summary of rates from the 2012 study. ETS rate levels have increased since 2012, most likely attributable to system growth and inflation effects over time; note however some jurisdictions have increased more than others. For instance, the ISO-NE rate has nearly doubled, most likely due to transmission expansions in the region. These differences suggest that the pace and magnitude of transmission investment over time, as well as system usage, differs across the jurisdictions between the two study periods.

CRA also observes that there are no rate design changes since 2012 for those jurisdictions covered in that study. Table 1 also shows a wide disparity among ETS rate levels. For instance, demand-based rates range from $8.69/kW-year (SPP) to $163.62/kW-year (ISO-NE). Energy-based rates, on the other hand, range from $1.85/MWh (Ontario) to $15.84/MWh (CAISO). Disparities among rate levels also were present in 2012. Finally, CRA observes that some tariffs offer firm and non-firm export services which are priced equally. The primary difference between firm and non-firm services is that export transactions using the latter are the first to be recalled or curtailed by the ISO at any time and at its discretion, for instance, when outages reduce transfer capability. The rules that specify the circumstances under which an ISO may recall non-firm service vary in each jurisdiction. Other jurisdictions do not specify a firm or non-firm basis of service for exports per the tariff service definitions.

Please refer to Appendix A for additional tables that provide an expanded summary of current ETS rates. Table 3 presents rates in the currency and rate format (capacity or energy) as

[5] All US market USD values converted at January 20, 2021 rate of 0.79 CAD/USD - source based on Bank of Canada daily rates - https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates

they appear in posted tariffs[6]; Table 4 presents the same but all in Canadian dollars; and Table 5 presents the rates in Canadian dollars and in an energy-based format (assuming a 100% load factor conversion) to allow for comparability to the current Ontario ETS rate of $1.85/MWh.

Note: rate adders for ancillary services are shown in Appendix B

Table 1 – Summary of 2020 Rates for Export Transmission Service (CAD)

		Annual Service $/kW-year	Monthly Service $/kW-month	Weekly Service $/kW-week	Daily On-Peak Service $/kW-day	Daily off-Peak Service $/kW-day	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh
MISO	Firm	52.4801	4.3733	1.0092	0.2019	0.1438		
	Non-Firm		4.3733	1.0092	0.2019	0.1438	12.6154	5.9909
PJM	Firm	23.9089	1.9924	0.4597	0.0919	0.0657		
	Non-Firm		1.9924	0.4597	0.0919	0.0657	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		163.6226						
SPP[5]	Firm	8.6951	0.7246	0.1672	0.0334	0.0239		
	Non-Firm		0.7246	0.1672	0.0334	0.0239	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30			
	Non-Firm		6.51	1.50	0.21		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service irrespective of time of day.
3. Non-firm service not offered.
4. Firm service not offered.
5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $16.8/kW-year to $71.8/kW-year for annual firm service, and $1.92/MWh to $8.19/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specific on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

6 Some rates are stated on a demand-basis (rates charged on a unit of capacity unit basis – $ per MW or kW) and others on an energy-basis (rates charged on a unit of energy basis – $ per MWh, or kWh).

Table 2 – Summary of 2012 Rates for Export Transmission Service (CAD)[7]

		Annual $/kW-year	Month $/kW-month	Week $/kW-week	Day-Peak $/kW-day	Day-Off-Peak $/kW-day	Hour-Peak $/MWh	Hour-Off-Peak $/MWh
MISO	Firm	29.3756	2.448	0.5649	0.1130	0.0805		
	Non-Firm		2.448	0.5649	0.1130	0.0805	7.0608	3.3531
PJM	Firm	18.669	1.556	0.3590	0.0718	0.0513		
	Non-Firm		1.556	0.3590	0.0718	0.0513	4.4875	2.1350
NYISO	$2.9233/MWh - $5.5056/MWh							
ISO-NE	Firm	63.135					7.207	
	Non-Firm							
Trans-Énergie	Firm	72.45	6.04	1.39	0.28			
	Non-Firm	72.45	6.04	1.39	0.20		8.24	

7 The 2012 Jurisdictional Review report used the average rate of exchange during 2011 that was C$1.0 = US $1.0117; Source: Bank of Canada.

3. Regulatory Research by Region

CRA researched regulatory rationale for the ETS rates reviewed. CRA's steps included a systematic search and review of relevant documentation for the various ISOs/RTOs and the FERC in the United States, and appropriate commissions and market operators in Canada. Our research covered applicable regulatory orders and related documentation.

3.1. ISO-New England (ISO-NE)

In New England, the outbound point-to-point rates – or Through or Out Service (TOUT)[8] – setting process was adopted as part of the tariff reform in response to FERC's restructuring directive in Order No. 888. Specifically, the process used at the time by the New England Power Pool (NEPOOL) was considered compliant by the FERC and adopted during the inception of the ISO.[9]

Notably, there is no difference between firm and non-firm transmission service as to rates; however, the ISO could curtail any external transactions to maintain system reliability. Per the ISO-NE procedure, *"All curtailments are determined in a nondiscriminatory manner and an appropriate reason is indicated."*[10] ISO-NE and NYISO have entered into a reciprocal agreement, in the form of a memorandum of understanding (MOU), that has adopted an exception to the rule such that the TOUT rate is reduced to zero for any Through or Out Service transaction that goes through or out of the New England Control Area and has the New England/New York Control Area boundary as its Point of Delivery.[11] The ISO-NE tariff states rates on an annual $/kW-Yr basis, however service can be provided on hourly and monthly terms.[12]

3.2. New York ISO (NYISO)

In a similar way that ISO-NE applies, NYISO's method derives from the pre-ISO era rates used by the NY Power Pool (NYPP). These power pool rates were later adopted during the formation of the NYISO on December 1, 1999.[13] NYISO provides Point to Point service with the Firm Point to Point rate including specific Transmission Owner charges needed to recover the embedded cost of transmission. As per the NYISO OATT Schedule H, the wholesale transmission service charge (TSC) recovers each Transmission Owner's embedded costs, as well as the transmission component of their control area costs, and is determined separately for each load zone. The TSC is adjusted to account for revenues from grandfathered

8 In accordance with Section II.25.3 of the ISO-NE OATT, a Transmission Customer pays to the ISO the RNS Rate for Through or Out Service reserved for it in accordance with Section II.24 of the ISO-NE OATT. The Transmission Customer shall also be obligated to pay any applicable ancillary service charges.

9 *New England Power Pool,* 83 FERC P. 61,045 at 61,237 (1998)

10 ISO New England Operating Procedure No. 9 Scheduling and Dispatch of External Transactions, https://www.iso-ne.com/static-assets/documents/rules_proceds/operating/isone/op9/op9_rto_final.pdf

11 ISO-NE Transmission, Markets & Services Tariff, Section II25.3, https://www.iso-ne.com/static-assets/documents/regulatory/tariff/sect_2/oatt/sect_ii.pdf#page=47 I

12 ISO-NE's rate per hour for Through or Out Service is the annual TOUT Rate divided by 8760. Similarly, the month rate is the annual divided by 12.

13 FERC Docket OA97-470 - FERC order establishing of New York Independent System Operator.

agreements, financial transmission rights, and congestion payments. The net of all these quantities for each Transmission Owner is divided by the total annual billing quantities (MWh) to give a $/MWh rate. The purpose of this rate design, developed by the Transmission Owners during the formation of the NYISO, was to allocate charges and revenues for exports and wheel-through transactions in a way that reflected the use of multiple Transmission Owners' facilities by a single transaction, as well as the divergence of revenue requirements for each Transmission Owner.

Per the NYISO formation Order: *"Export transactions and through transactions pay a charge based on the cost of the transmission provider that owns the intertie which serves as the point of delivery to the adjacent control area."*[14,15] Section 3.1.6 of the NYISO OATT provides details related to the curtailment of Firm Point to Point service *"In the event that a curtailment of the NYS Transmission System…Curtailments will be made on a non-discriminatory basis to the Transactions that effectively relieve the Constraint."*[16] Non-Firm Point to Point Transmission Service is not available in the markets administered by the NYISO.[17] Per the MOU described above, there are no Transmission Service Charges for transactions with Point of Delivery to the New England border.

3.3. Pennsylvania-New Jersey-Maryland Interconnection (PJM)

Under the guidance of FERC Order No. 888, PJM adopted a transmission service structure that includes firm and non-firm point-to-point transmission service to each zone in PJM and to the border of the PJM Region under Part II of the PJM Tariff ("Border Rate"). The ETS rate reflects the composite or average cost of service in the PJM Region under the principle that all of the facilities are available to provide such service.

The Border Rate does not apply to any point-to-point transmission service or network service to serve load in the Midcontinent Independent System Operator, Inc. (MISO). This reciprocal arrangement falls under the Joint Agreement between MISO and PJM and is incorporated in Schedules 7 and 8 that provide the Border Rate.[18]

The Border Rate level has not changed significantly since 2012. In 2019, PJM's proposed Tariff revisions were accepted by the FERC and included changes in the Border Rate calculation methodology going from the 12-month coincident peak sum to the sum of all zonal peak loads for the purposes of cost allocation and billing units for the rates; changes also included addition of a methodology for updating rates on an annual basis beginning after 2020 to more accurately reflect the cost of transmission and other services. This update also includes an annual update for zonal transmission system costs. The regulatory rationale

14 FERC Docket No. ER97-1523 Page 15

15 Note that "cost" refers to a total transmission cost burden assessed based on the zone in which the load is located (or, in the case of exports, the zone of exit), rather than a subset of costs for export and through or out service.

16 NYISO OATT, Section 3.1.6

17 NYISO OATT, Section 3.2 of

18 In Docket ER19-2105, the PJM TOs noted that under an agreement approved by the FERC, there is no charge under schedules 7 and 8 for points of delivery within the MISO region. The JOA is located here: https://www.pjm.com/directory/merged-tariffs/miso-joa.pdf

behind this move appears to be to lower the Border rate so that it is more comparable to the Network Integration Service[19] Rate charged to PJM customers for open access to the transmission system.[20]

3.4. Southwest Power Pool (SPP)

Order No. 888 principles were applied to the ETS rate design for SPP as well. Since the inception of the two organizations, there has been limited activity related to the update of design to ETS rates.

SPP Schedule 11 Through & Out rate is based on the sum of all base zonal ATRRs and 12 CP average system load and is offered on both a firm and non-firm basis. Schedules 7 (firm) and 8 (non-firm) also apply to point-to-point export service, where the transmission customer pays the zonal rate for the zone interconnected with the balancing authority area, external to the SPP region, that is the designated point of delivery. Where there is more than one Zone interconnected with such balancing authority area, the lowest zonal rate of the interconnected zones is applicable.

3.5. California ISO (CAISO)

CAISO uses energy-based determinants to derive its transmission rate. Firm annual billing units (MWh) are divided into total annual transmission revenue requirements for CAISO's high-voltage network system. Exports are charged the resulting high-voltage transmission access charge (HV-TAC) rate ($/MWh based) for each transaction.

In 2000, FERC approved a 10-year transition period to a uniform ISO-wide HV-TAC to encourage high-cost transmission facilities to join the ISO. Over the transition period, the ISO-wide high-voltage revenue requirement was blended with each transmission owner's individual high-voltage revenue requirement.[21]

In 2014, CAISO's OATT evolved to accommodate a Western Energy Imbalance Market (WEIM), a sub-hourly exchange of renewable power across multiple balancing authority areas[22] outside the ISO in the Western United States. CAISO's OATT assesses high-voltage wheeling access charges upon exports from transmission facilities with voltage ratings of 200 kV or higher. In 2014, FERC waived high-voltage wheeling access charges for exports sinking to WEIM-participating balancing authority areas.

In 2018, CAISO internally proposed redesigning its fully volumetric tariff to a hybrid energy-based and demand-based ETS rate. This proposal has been deferred.

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19 Network Integration Service relies on the use of the entire transmission network for transmitting energy; this differs from Point to Point service that assumes a particular receipt and delivery path.

20 FERC Docket ER19-2105, pp. 11 and 18

21 CAISO, 91 FERC 61,205 ¶ (2000).

22 A balancing authority is a utility or similar planning entity that plans generation and load for a small geographic area, the balancing authority area. In the case of the WEIM, balancing authorities will exchange power on a 15-minute basis.

3.6. Alberta Electricity System Operator (AESO)

AESO offers two rates: one a transmission rate from merchant interties (Rate XOM)[23] and the other an export transmission rate from an AESO network intertie (Rate XOS).[24] The primary billing determinant in Rates XOS and XOM is energy consumption, at a flat rate.

AESO's export service is non-firm, fulfilled only when sufficient capacity exists on the transmission system to accommodate the capacity scheduled for export.[25] The export service features the following attributes:

- A $500/month transaction fee is added for all participants which utilize the service.[26]
- The market participant may contract for export opportunity service for a term from one hour to one month.[27]
- Exports are subject to loss correction of 1%[28] and a trading charge of $0.38/MWh.[29]

Decision 2013-325[30] added the merchant rate export opportunity to the tariff with the same function, classification, and allocation of the AESO's revenue requirement as directed in Decision 2010-606.[31]

Decision 2013-421[32] plus a 2018 follow-up study for AESO tariff applications include cost allocation case studies that influence rates XOS and XOM. Please refer to Appendix C for more detail about the cost allocation studies.

Firm Rate Consideration

Alberta has a history of considering firm export rates; however current export rates continue to be offered only on a non-firm basis. Some of the issues and reasons for not implementing

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23 AESO tariff, XOM rate, https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-export-opportunity-merchant-service-xom/download/Rate-XOM-Effective-Jan-1-2021.pdf

24 AESO tariff, XOS rate, https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-export-opportunity-service-xos/download/Rate-XOS-Effective-Jan-1-2021.pdf

25 Ibid.

26 Ibid.

27 Ibid.

28 Rider E Calibration Calculation Factor for the Fourth Quarter of 2020, https://www.aeso.ca/assets/Uploads/2020-Q4-Rider-E-Report-Layout.pdf

29 Energy market trading charge, https://www.aeso.ca/market/energy-market-trading-charge/

30 Decision 2013-325, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2013/2013-325.pdf

31 Decision 2010-606, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010-606.pdf

32 Decision 2013-421, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2013/2013-421.pdf

a firm rate were given include: congestion management, lack of sufficient transfer capability, reliability of the lines, and administrative complexities.[33] [34] [35] [36] [37]

3.7. TransÉnergie (Hydro-Québec)

Québec offers firm and non-firm point-to-point transmission service and uses demand as its primary point-to-point rate determinant. Decisions D-2016-029, D-2016-046, and D-2016-050[38] established HQ's firm (short and long term) and non-firm (short and long term) tariff terms.

Export rates are discounted for certain transactions.[39] Hydro-Québec offers discounts when it estimates that transactions are otherwise unlikely to clear at the full tariff rate, i.e., during times of low export pricing in neighboring jurisdictions. Discounting is based on allocation of export value between transmission generation assets. This is done on an opportunistic, market-based approach, rather than a set formula.

33 Decision 2002-99, p. 100, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2002/2002099.pdf

34 Decision 2005-096, Section 5.8, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2005/2005096.pdf

35 Decision 2007-106, Section 7, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2007/2007106.pdf

36 Decision 2010-606, Section 9.2, https://www.auc.ab.ca/regulatory_documents/ProceedingDocuments/2010/2010606.pdf

37 Firm rates were considered on the basis of the internal point system access service (Demand Transmission Service, “DTS”). The DTS comprises of components charged on a capacity and energy basis, including a Bulk System Charge, Regional System Charge, and Point of Delivery Charge. (https://www.aeso.ca/rules-standards-and-tariff/tariff/rate-dts-demand-transmission-service/download/Rate-DTS-Effective-Jan-1-2021.pdf)

38 Hydro-Québec OATT, Schedules 9 and 10, http://www.oatioasis.com/HQT/HQTdocs/HQT_OATT_2017_2016-12-13.pdf

39 Testimony of Philip Raphals, Peter Bradford, and E.O. Disher, 2000, https://www.rncreq.org/pdf/R-3401-98%20RNCREQ%20Rapport.pdf

Appendix A – Expanded Summary of 2020 ETS Rates

Table 3 – Summary of Rates for Export Transmission Service – As Reported in Native Tariffs

The ETS rates by jurisdiction are provided below – Note that MISO, PJM, NYISO, ISO-NE, SPP and CAISO rates are stated in USD; rates for Canadian jurisdictions stated in CAD.

		Annual Service $/kW-year	Monthly Service $/kW-month	Weekly Service $/kW-week	Daily On-Peak Service $/kW-day	Daily Off-Peak Service $/kW-day	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh	Schedule/Service Name
MISO	Firm	41.4593	3.4549	0.7973	0.1595	0.1136			Schedule 07: Long-Term and Short-Term Firm Point-To-Point Service Schedule 07: Michigan Long-Term and Short-Term Firm Service
	Non-Firm		3.4549	0.7973	0.1595	0.1136	9.9662	4.7328	Schedule 08 - Non-Firm Point-To-Point Transmission Service Schedule 08: Michigan Non-Firm Point-to-Point Transmission Service
PJM	Firm	18.888	1.574	0.3632	0.0726	0.0519			Schedule 7: Long-Term Firm and Short -Term Firm Point to Point Transmission Service
	Non-Firm		1.574	0.3632	0.0726	0.0519	4.54	2.16	Schedule 8: Non-Firm Point-to-Point Transmission Service
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $3.25 per MWh (Hydro-Québec) to $6.12 per MWh (PJM).							Schedule 7: Firm Point-to-Point Transmission Service Schedule 8: Non-Firm Point-to-Point Transmission Service
ISO-NE[1]		129.26182							Schedule 8: A Transmission Customer shall pay to the ISO the Pool PTF Rate for Through or Out Service reserved Schedule 9: Provides the pool PTF rates for ISO-NE
SPP[5]	Firm	6.8691	0.5724	0.1321	0.0264	0.0189			Schedule 11: Through and Out Zonal Point-to-Point Service
	Non-Firm		0.5724	0.1321	0.0264	0.0189	1.651	0.784	
CAISO[4]								12.5201	Schedule 3: Regional Access Charge and Wheeling Access Charge
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30				Schedule 9 : Long-Term and Short-Term Firm Point-to-Point Transmission Service
	Non-Firm		6.51	1.50	0.30		6.51		Schedule 10: Non-Firm Point-to-Point Transmission Service
Alberta[4]							8.28		Export Opportunity Service, Export Opportunity Merchant Service (for merchant lines)
Ontario[6]							1.85		ETS Rate Schedule included as part of Ontario Uniform Transmission Rate Schedule

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service regardless of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $13.3/kW-year to $56.7/kW-year for annual firm service, and $1.52/MWh to $6.47/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Table 4 – Summary of Rates for Export Transmission Service – All Stated in CAD

The ETS rates by jurisdiction are provided below - *All US market USD values converted at January 20, 2021 rate of 0.79 CAD/USD (source based on Bank of Canada daily rates - https://www.bankofcanada.ca/rates/exchange/daily-exchange-rates/).*

		Annual Service $/kW-year	Monthly Service $/kW-month	Weekly Service $/kW-week	Daily On-Peak Service $/kW-day	Daily Off-Peak Service $/kW-day	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh
MISO	Firm	52.4801	4.3733	1.0092	0.2019	0.1438		
	Non-Firm		4.3733	1.0092	0.2019	0.1438	12.6154	5.9909
PJM	Firm	23.9089	1.9924	0.4597	0.0919	0.0657		
	Non-Firm		1.9924	0.4597	0.0919	0.0657	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		163.6226						
SPP[5]	Firm	8.6951	0.7246	0.1672	0.0334	0.0239		
	Non-Firm		0.7246	0.1672	0.0334	0.0239	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	78.06	6.51	1.50	0.30			
	Non-Firm		6.51	1.50	0.21		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly, or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service regardless of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedules 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $16.8/kW-year to $71.8/kW-year for annual firm service, and $1.92/MWh to $8.19/MWh non-firm.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Table 5 – Energy-Only Rates for Export Transmission Service – All Stated in CAD$/MWh

The ETS rates by jurisdiction are provided below – *Note that all rates are stated on CAD$/MWh basis, converted at 100% load factor, and January 20th, 2021 exchange rate of 0.79 CAD/USD.*

		Annual Service $/MWh	Monthly Service $/MWh	Weekly Service $/MWh	Daily On-Peak Service $/MWh	Daily Off-Peak Service $/MWh	Hourly On-Peak Charge $/MWh	Hourly Off-Peak Charge $/MWh
MISO	Firm	5.9909	5.9908	5.9909	8.4124	5.9916		
	Non-Firm		5.9908	5.9909	8.4124	5.9916	12.6154	5.9909
PJM	Firm	2.7293	2.7293	2.7291	3.8291	2.7373		
	Non-Firm		2.7293	2.7291	3.8291	2.7373	5.7468	2.7342
NYISO[3]		The energy-based rate for the Firm PTP service is different for each transmission company at the seam of NYISO, and it ranges between $4.11 per MWh (Hydro-Québec) to $7.75 per MWh (PJM).						
ISO-NE[1]		18.6784						
SPP[5]	Firm	0.9926	0.9925	0.9926	1.3924	0.9968		
	Non-Firm		0.9925	0.9926	1.3924	0.9968	2.0899	0.9924
CAISO[4]								15.8482
Trans-Énergie[2]	Firm	8.9110	8.9178	8.9041	12.5000			
	Non-Firm		8.9178	8.9041	8.7500		8.91	
Alberta[4]							8.28	
Ontario[6]							1.85	

1. ISO-NE does not distinguish between Firm and Non-Firm transactions and does not offer monthly, weekly or daily transmission services. It offers hourly transmission service, and this is noted in Table 1 of Section 3 of this report.
2. TransÉnergie offers the same daily transmission service irrespective of time of day.
3. Non-firm service not offered.
4. Firm service not offered.

5. Schedule 7 and 8 rates also apply on a zonal basis for Point-to-Point transactions, in a range of $1.52/MWh to $6.47/MWh.
6. Not clearly defined as either firm or non-firm, although rate is specified on energy basis and line capacity cannot be reserved for extended periods, therefore implied non-firm.

Appendix B – Rate Adders

Table 6 – MISO Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

MISO			
Item	**Peak $/MWh**	**Off-Peak $/MWh**	**Source**
Scheduling, System Control, and Dispatch Service	0.1901	0.0903	Schedule 1
Reactive Supply and Voltage Control	0.4859	0.2308	Schedule 2
ISO Cost Recovery Adder	0.1144	0.1144	Schedule 10
Network Upgrade Charge for Transmission Expansion Plan	0.8865	0.4210	Schedule 26
Black Start Service	0.0080	0.0038	Schedule 33
Cost Recovery of NERC Recommendation or Essential Action	0.0197	0.0094	Schedule 45
FTR-related	0.0072	0.0072	Schedule 16
Market Administration	0.0932	0.0932	Schedule 17
Local Balancing Authority Cost Recovery	0.0127	0.0127	Schedule 24
Total Charges	***1.8177***	***0.9828***	

Table 7 – PJM Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

PJM		
Item	**$/MWh**	**Source**
PJM Administrative Fees	0.47	2019 State of the Market Report for PJM - Introduction Table 1-10
NERC/RFC	0.03	
Voltage Control	0.44	
Black Start	0.08	
Operating Reserve	0.04	
Regulation & Frequency Control	0.12	
Synchronized Reserve	0.04	
Transmission Owner (Schedule 1A)	0.09	
Transmission Enhancement Cost Recovery	0.55	
Total Charges	***1.86***	

Table 8 – NYISO Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

NYISO		
Item	**$/MWh**	**Source**
NYISO Cost of Operations	0.73	NYISO Monthly Report - Appendix B Page 38 (Updated to October 2020)
FERC Fee Recovery	0.10	
Voltage Support and Black Start	0.45	
Operating Reserve	0.61	
Regulation & Frequency Control	0.11	
Uplift: Statewide Share	(0.13)	
Total Charges	***1.87***	

Table 9 – ISO-NE Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

ISO-NE			
Item	**$/MWh**	**$/kW-year**	**Source**
Scheduling, System Control, and Dispatch Service	0.199	1.745	Schedule 1
Reactive Supply and Voltage Control Service	0.125	1.093	Schedule 2
Total Charges	***0.324***	***2.838***	

Table 10 – SPP Ancillary Services and Other Charges Applicable to ETS Transactions (USD)

	SPP		
Item	**Peak $/MWh**	**Off-Peak $/MWh**	**Source**
Scheduling, System Control, and Dispatch Service	0.3060	0.1450	Schedule 1
Tariff Administrative Charges	0.3130	0.3130	Schedule 1A
Reactive Supply and Voltage Control	0.0040-0.6580	0-0.0200	Schedule 2
FERC Assessment Charge	0.0834	0.0834	Schedule 12
Total Charges	***0.7064-1.3604***	***0.5414-0.5614***	

Table 11 – TransÉnergie Ancillary Services and Other Charges Applicable to ETS Transactions (CAD)

	TransÉnergie						
Item	**Annual per kW reserved**	**Monthly per kW reserved**	**Weekly per kW reserved**	**Daily Firm per kW reserved**	**Daily Non-Firm per kW reserved**	**Daily Non-Firm per kW reserved**	**Source**
System Control Service	Currently this is not a separate rate and is included in transmission charge.						Schedule 1
Voltage Control Service	0.31	0.03	5.96	1.19	0.85	0.04	Schedule 2
Frequency Control Service	0.31	0.03	5.96	1.19	0.85	0.04	Schedule 3
Energy Imbalance Receipt - shortfall	Imbalance service charges are calculated and applied based on conditions in neighboring markets at time of service.						Schedule 4
Energy Imbalance Delivery - excess							Schedule 5
OR – Spinning Reserve	1.15	0.10	22.12	4.42	3.15	0.13	Schedule 6
OR – Non–Spinning Reserve	0.57	0.05	10.96	2.19	1.56	0.07	Schedule 7
Total Charges	***2.34***	***0.21***	***45.00***	***8.99***	***6.41***	***0.28***	

Appendix C – AESO's OATT Cost Causation Study

London Economics International LLC developed transmission cost causation studies for the years 2014–2016 and 2018–2020 to support AESO's tariff filings. The transmission cost allocation studies set functionalization and classification values for the AESO tariff. The 2014 and 2018 cost causation studies analyze four key areas: (i) functionalization of transmission facility owner related capital costs, for both existing and planned assets; (ii) functionalization of related operations and maintenance costs; (iii) classification of all costs functionalized as bulk and regional; and (iv) implementation considerations (i.e., discussion of the potential impact of implementing the functionalization and classification results on rates/recovery of the revenue requirement). The 2018 study involves an identical analysis using updated inputs that became available since the time the 2014 study was performed.

Though these studies are not specific to export rates, they influence the $/MWh transmission rates developed in Rates XOS and XOM. For example, in accordance with Section 34 of the Transmission Regulation in Alberta's Electric Utilities Act,[40] the cost of transmission losses is allocated to generators, export and import services, and demand opportunity service.

Each year, the cost allocation studies are updated to reflect the Tariff year's forecast revenue requirement, wires costs functionalization and classification, and forecast billing determinants.[41] Rates XOS and XOM (specifically, levels of dollar-based and percentage of pool price amounts) are allocated according to their cost burden on the entire transmission system.

AESO's 2021 Tariff includes the cost causation study framework for the entire transmission system, with updated calculations for 2021, in Appendix B. Allocations to export rates are found in Tab B-11.[42]

The calculation for determining the $8.24/MWh XOS/XOM rate based on the 2018-2020 transmission cost allocation study is as follows:

40 Province of Alberta, Electric Utilities Act (2007) https://www.qp.alberta.ca/documents/Regs/2007_086.pdf

41 Alberta Electric System Operator 2018 ISO Tariff Compliance Filing Pursuant to Decision 22942-D02-2019 and 2020 ISO Tariff Update Application, January 31, 2020, https://www.aeso.ca/assets/Uploads/25175-X0002-2018ISOTariffComplianceFilingandUpdateAp-0002.pdf

42 Alberta Electric System Operator 2021 ISO Tariff Application, November 12, 2020 https://www.aeso.ca/assets/Uploads/AESO-2021-ISO-Tariff-Update-Application.pdf, Appendix B, Tab B-11 https://www.aeso.ca/assets/Uploads/Appendix-B-2021-Rate-Calculations.xlsx

Component	Fixed		Usage		Total	
Export Opportunity Service (XOS/XOM) Rates	**XOS/XOM, $/MWh**					
Connection – Bulk System	$	3.46	$	1.21	$	4.67
Connection – Regional System		1.58		0.92		2.50
Connection – POD		-		-		-
Operating Reserve		-		1.07		1.07
Voltage Control		-		-		-
Other System Support		-		-		-
Total XOS Costs	$	5.03	$	3.20	$	8.24

Source: see footnote 40

Market Implications of the Export Transmission Service Rate

July 2021

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Table of Contents

1. Executive Summary

In this report, the Independent Electricity System Operator (IESO) addresses the market implications of the Export Transmission Service (ETS) rate in response to the Ontario Energy Board's (OEB) Decision and Order in EB-2019-0082. The report presents an overview of intertie trading in Ontario in light of the recent market rule changes, discusses the implications of an increased ETS rate for the Ontario market, and comments on jurisdictional comparisons and the suitability of the OEB's pole attachment approach for setting the ETS rate.

When considering any adjustment of the ETS rate, it is important for the OEB and interveners to appreciate the following aspects of intertie trading:

- **Intertie trading is a competitive marketplace:** As part of the regular operation of the electricity market, Ontario efficiently imports and exports electricity on an hour-by-hour basis delivered across interties with two Canadian provinces (Manitoba and Quebec) and three U.S. states (Minnesota, Michigan, and New York). Electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. These factors make intertie capacity a scarce resource resulting in traders competing for access to these resources.
- **Exports from Ontario provide operational and economic benefits:** In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions. From an economic standpoint, exports of energy from Ontario have contributed approximately $330-520 million annually to Ontario between 2017 and 2020. Intertie trading reduces total costs for Ontario consumers by generating revenues, contributing to fixed system costs and avoiding incremental system costs.
- **Exporters contribute to the costs of the transmission system through "congestion rent":** In addition to paying the ETS rate, intertie traders exporting energy from Ontario pay the Intertie Congestion Pricing (ICP), a dynamic charge set based on its market value to traders, administered through the IESO-administered market. ICP revenues are collected entirely from intertie importers and exporters for the purpose of offsetting transmission service charges paid for all transmission customers. Since 2017, an average of $160 million per year of ICP revenue has been returned in reduced transmission costs, the majority of which has gone to domestic consumers.
- **Market design changes**: Market design changes since 2015 provide greater certainty on how Transmission Rights Clearing Account (TRCA) funds are disbursed. ICP revenues are now distributed on a semi-annual basis. The IESO also improved the design of the Transmission Rights market to increase the amount of revenues available to be disbursed and change the proportion of the distribution to return almost all available funds to domestic consumers.

The 2021 Elenchus Report[1] presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option

[1] EB-2021-0110, Exhibit H-09-01-01

represents a significant increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh).

The IESO expects the market implications of a higher ETS rate would be as follows:

- **Corresponding decrease in ICP revenue:** The IESO expects that any increase in revenue resulting from a higher ETS would be offset by an equivalent reduction in revenue from the ICP, which in turn will decrease the amount of disbursements from the TRCA paid to Ontario consumers. The ICP and ETS are both transaction costs that negatively impact the profit margins of competitive intertie trade. The ICP and ETS have an offsetting relationship such that an increase in the ETS will lead to a proportionate decrease in the ICP. This offsetting relationship means that, assuming the quantity of exports remains constant, the overall value that Ontario ratepayers derive from exports would remain unchanged even if the ETS rate is increased.
- **Reduction of exports and adverse impact to operational/economic benefits:** Exports are highly price-sensitive. A higher ETS would have the effect of reducing energy exports from Ontario and by extension the operational and economic benefits that those lost exports provide. In contrast to the dynamic nature of the ICP, the ETS is a fixed charge applied on all exports regardless of market conditions. This means there will be occasions when market conditions are such that the ETS charge will make exports uneconomic and prevent an otherwise economic export from transacting. Even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. Less exports will mean less operational and economic benefits provided by exports, which is likely to increase system costs for domestic consumers. Prior analysis demonstrates that in one case increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes (expressed as a percentage of status quo volumes).[2]

Revenue from the ETS is only one component of the value that Ontario receives from exports and historically has been the smallest component of the economic benefits associated with exports. When setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will reduce the value of interties, leading to less system flexibility and higher costs for Ontario consumers.

2. Introduction

In its Decision and Order in EB-2019-0082, the OEB directed Hydro One Networks Inc. (HONI) to consult with the IESO in the preparation of an updated ETS jurisdictional review that includes an assessment of market implications:

> *File an updated ETS jurisdictional review that provides the rates in other jurisdictions, rationale behind those rates and market implications. Hydro One is expected to discuss the approach to a jurisdictional review with the IESO and OEB*

[2] IESO internal analysis based on data presented in Export Transmission Service (ETS) Tariff Study, Charles River Associates, May 16, 2012, Pg. 18-20

staff to determine the best approach to complete a review before Hydro One's next transmission rebasing application[3].

The last ETS jurisdictional review was prepared by Charles Rivers & Associates (CRA) in 2012 as part of a stakeholder engagement undertaken by the IESO (the 2012 CRA Study)[4]. The 2012 CRA Study was filed with the OEB in EB-2012-0031 and was the subject of an extensive review in that proceeding. In addition to reviewing tariff rates and structures in neighbouring markets, the 2012 CRA Study assessed the implications of various ETS options on the Ontario electricity market as a whole.

HONI has retained Elenchus Research Associates Inc. (Elenchus) to prepare an update to the Export Transmission Service Rate Cost Allocation Methodology Report (the 2021 Elenchus Report) in response to the OEB's direction in EB-2019-0082. The 2021 Elenchus Report presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option represents an increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh).

The 2021 Elenchus Report contains a review of cost allocation methodologies used in other North American jurisdictions and concludes that transmission rate-setting in Ontario differs considerably from the processes used in these jurisdictions. One cost allocation methodology in the 2021 Elenchus Report incorporates principles from the OEB's decision on Pole Attachment Charges (EB-2015-0304).

The 2021 Elenchus Report does not examine the implications of a higher ETS rate for the Ontario electricity market as a whole. HONI and the IESO have agreed that, given the IESO's role as system operator, it would be appropriate for the IESO to perform a qualitative review of the implications of a higher ETS rate on the Ontario electricity market. Given the significant time and expense already incurred to study the ETS rate, the IESO's view was that the current work should avoid unnecessary duplication of past studies and focus on new and informative insights.

In EB-2012-0031, the IESO concluded that, based on the 2012 CRA analysis, reducing ETS rate to zero "would best encourage the efficient use of electricity and promote economic efficiency in the generation, transmission and sale of electricity"[5]. There was however uncertainty at the time as to the extent to which ICP revenues (also referred to as "congestion rent") would defray domestic consumer costs[6] and, as the IESO acknowledged, this uncertainty meant the zero ETS rate would result in increased consumer costs unless ICP revenues were allocated to consumer costs[7]. The OEB determined that, while it may be appropriate to depart from strict cost causality where there will be demonstrable and significant benefits from an alternative approach, it was not justified considering the uncertainties around the benefits of a more efficient market.

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[3] EB-2019-0082 Decision and Order, April 23, 2020, Pg. 183

[4] Export Transmission Service (ETS) Tariff Study – Review of Rates in Neighbouring Markets, Charles River Associates, May 16, 2012

[5] IESO Submission in EB-2012-0003, March 8, 2013, Pg. 5

[6] As noted by the OEB, *"There was disagreement amongst the experts, and amongst the parties, as to how the allocation of the producer surplus and ICR [ICP] should be viewed. The allocation of these amounts to Ontario consumers, either directly or indirectly, impacts which ETS rate option appears to provide the greatest benefit",* OEB Decision and Order for 2013 Export Transmission Service Rate, June 6, 2013, Pg. 6

[7] IESO Submission to EB-2012-0031, March 8, 2013, Pg. 10

Exporters contribute to the cost of the transmission system through two mechanisms. The first mechanism is through the ETS rate, a fixed volumetric charge, which is the focus of this rate application. The second mechanism is through the ICP mechanism, a dynamic charge set based on its market value to traders, administered through the IESO-administered market. ICP revenues are collected entirely from intertie importers and exporters for the purpose of offsetting transmission service charges[8].

Since the 2012 CRA study, the IESO has passed market design changes that have clarified how ICP revenues reduce transmission costs for ratepayers. Since 2017, the ICP mechanism has disbursed approximately $160 million per year, primarily to domestic customers to offset transmission charges in addition to the approximately $30-40 million per year collected from exporters through the ETS rate.

In this report, the IESO will present an overview of intertie trading in the Ontario market in light of the recent rule changes, discuss the implications of an increased ETS for the Ontario market, and comment on jurisdictional comparisons and the suitability of the OEB's pole attachment approach for setting the ETS rate.

3. Overview of Intertie Trading in the Ontario Market

The Competitive Nature of Intertie Trading

As part of the regular operation of the electricity market, Ontario imports and exports electricity on an hour-by-hour basis delivered across interties with two Canadian provinces (Manitoba and Quebec) and three U.S. states (Minnesota, Michigan, and New York).

Being part of an interconnected grid means that Ontario has the ability to simultaneously export and import power across multiple locations as part of the regular operation of its electricity market, to provide operational and planning flexibility, as well as enhance the reliability, resiliency and cost-effectiveness of the electricity system. The operational and economic benefits of intertie trading is discussed in greater detail below.

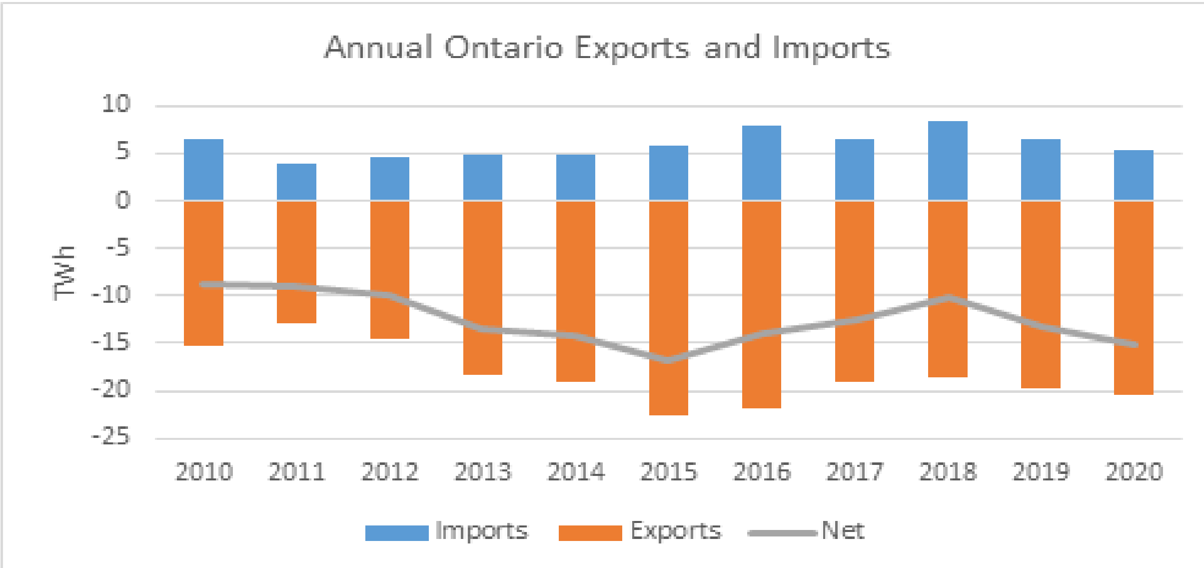
Electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. Traders look for "price spread" opportunities across the different interconnected markets and make profit when they can buy energy at a lower price in one jurisdiction and export it to another jurisdiction to be sold for a higher price. Electricity prices can differ between jurisdictions for a variety of reasons, including different supply mix characteristics, weather, demand patterns, as well as market and system conditions.

For example, if Ontario is expecting a surplus of energy during the overnight hours, electricity market prices in Ontario would likely be lower relative to its neighbouring jurisdictions, signaling a trading

[8] IESO Market Rules, Chapter 8, Section 4.18.2.

opportunity. A trader could export power from Ontario and earn a profit equal to the price differences between the two jurisdictions less any transaction costs. In the case of an export from Ontario, the relevant transaction costs include the ETS, the ICP and Uplifts. The impact of these factors on intertie trading is explored further below.

Historically, Ontario has been a net exporter of electricity, primarily to the U.S. jurisdictions, and a net importer from Quebec.



Source: IESO Power Data (https://www.ieso.ca/en/power-data/supply-overview/imports-and-exports)

The Role of Intertie Trading in System Planning

The IESO undertakes reliability assessments to ensure the system meets the needs of domestic consumers. Ontario's interties provide reliability benefits (e.g., supply and demand balancing, frequency and regulation control, and other emergency measures), and the IESO plans the system, in accordance with established planning standards, to ensure export capability is sufficient to maintain system reliability and operability. However, the needs and activities of competitive exporters (e.g., volume and direction of transactions) are not considered when planning the transmission system, and so are not a primary driver of investment.

Considering this further, the electricity system in Ontario is designed to simultaneously supply domestic load and exports, at the full capability of the interties, for only a limited set of system conditions. When designing the system, the focus is on ensuring that domestic load can be supplied for a wide a range of system conditions. For many of these conditions planning standards do not require the system to support exports simultaneously.

It is also important to note that while the IESO provides market participants and consumers with the same access to grid service,[9] the way the system is designed and the priority given to exporters results in exports being subject to more frequent service interruption compared to domestic load. Exporters can be curtailed for more reasons than Ontario consumers, including internal

[9] See Electricity Act, 1998, SO 1998, c. 15, Schedule A, Section 26 (Non-discriminatory access)

adequacy or reliability issues in neighbouring jurisdictions. As a result, the IESO curtails exports for reliability reasons more often than domestic load.[10]

In summary, IESO planning assessments do consider maintaining export capability where required to ensure system reliability and operability, but do not specifically consider competitive exporter activity. Exporters have the same access to the transmission system as other market participants but they have lower priority than domestic load and this is reflected in the planning standards. Thus, from a system planning perspective, investments made within Ontario are primarily for supplying domestic load. On this basis, competitive exports are not a key driver of investment cost to the transmission system in Ontario.

The Operational Benefits of Intertie Trading

Interties with neighbouring jurisdictions provide a range of operational benefits and enhance system reliability for Ontario consumers. In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions.

The operational benefits provided by intertie trading include:

- **System Flexibility:** Intertie trading provides flexibility hour-by-hour to balance supply and demand in Ontario, including for response to near to real-time needs (e.g., unexpected generation or transmission outage) and other operational issues such as surplus baseload generation (SBG)[11]. Beyond SBG, interties also provide flexibility to balance the system resulting from changes in weather, demand patterns and other market conditions.
- **Ancillary Services:** Intertie trading helps maintain stability to the system through frequency and voltage regulation, and operating reserve. This is particularly so in real-time operations where interties help maintain system frequency and voltage to enable a reliable grid for Ontario consumers.
- **Regional Reliability:** Intertie trading supports regional grid reliability through the Simultaneous Activation of Reserve (SAR) program. SAR is a voluntary program with neighbouring jurisdictions to jointly activate reserves when one of the jurisdictions suffers a supply loss ≥500 MW. In this respect the interties enable Ontario to assist other jurisdictions during contingency events and support regional reliability.
- **Emergency Events:** In addition to the system flexibility that interties provide to manage unexpected events (e.g., one-off generation outages) they also provide support for emergency events (e.g., major system disruption) in Ontario through emergency imports. While the system is planned, built and operated to high levels of reliability based on Ontario resources, the interties provide the ability to draw on additional support from neighbouring jurisdictions during emergencies to maintain reliability for domestic consumers.

[10] Based on internal analysis, the IESO has curtailed export annually between 18-35% of all hours since 2016

[11] SBG occurs when domestic supply exceeds domestic demand. In these situations, interties provide flexibility to balance the grid by flowing electricity out of the province to neighbouring jurisdictions. In this respect, interties avoid the need for costly shut-down of domestic supply resources to balance the grid

- **Geographical Distribution:** The geographical distribution of interties around Ontario ensure all regions have access to the operational benefits of interties, and can support with local and system-wide reliability.

Intertie trading provides a range of operational benefits including system flexibility to balance supply and demand, and ancillary services to support grid stability. Interties also play a key role supporting system operations during unplanned or emergency events. From a broader perspective, interties support regional grid reliability and enable Ontario to assist other jurisdictions during contingency events.

The Economic Benefits of Exports

From an economic standpoint, exports of energy from Ontario have contributed between $330-520 million of value annually[12] to Ontario between 2017 and 2020 as shown on Table 1. Intertie trading reduces total costs for Ontario consumers by generating revenues, contributing to fixed system costs and avoiding incremental system costs.

Table 1: Value from Exports 2017-2020

$Millions	2017	2018	2019	2020
Congestion Rents Collected from Exports	208	191	134	99
Export Transmission Service Tariff (ETS)	35	34	37	38
Uplift collected from Exports	43	52	48	38
Avoided System Costs[13]	180	240	190	153
Total Value from Exports	**466**	**517**	**409**	**327**

Source: internal IESO analysis

Each of the identified economic benefits of exports are described in more detail below:

- **Congestion Rents:** As detailed in the next section, the IESO allocates access to the interties based on economics. When demand for intertie access is greater than the physical capability, the intertie is considered “congested” and traders are charged “congestion rent” in the form of the ICP – a premium for access based on willingness-to-pay. The ICP is collected by the IESO and ultimately disbursed back to domestic consumers and exporters to offset transmission service charges.[14] Since 2017, an average of approximately $160 million per year has been paid out in disbursements, the majority of which has been disbursed to domestic consumers.[15]

[12] Range of total value from exports 2017-2020. For more details, see Table 1

[13] Based on avoided nuclear and renewable resource curtailment, equal to 14TWh, 12TWh, 13TWh and 14TWh for 2017-20 respectively

[14] Revenue collected by the IESO from intertie congestion flows into the TRCA, which then disburses funds to market participants (domestic load and exporters) to offset transmission costs, Market Rules, Chapter 8, Section 4.18.2. The disbursement methodology is defined in the Market Rules, Chapter 9, Section 4.7. See Market Rule amendment: https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2020/iesotp-20200623-mr-00443-tr-clearing-account-amendment-proposal.ashx

[15] Average of TRCA disbursements 2017-2020. For more details, see Table 2

- **ETS:** Exporters contribute to the costs of maintaining a reliable transmission system by paying ETS and Uplift. The IESO typically collects between $30 and 40 million per year[16] through ETS which is charged each time an exporter flows electricity out of Ontario. ETS revenues collected are used to reduce transmission costs paid by domestic consumers.
- **Uplift**: Exporters also contribute approximately $40-50 million per year[17] in uplift charges for system reliability provided through Ancillary Services and Operating Reserve. The export contribution reduces the cost that has to be recovered from domestic consumers for these services.
- **Avoided System Costs**: Intertie trading helps Ontario avoid additional system costs that would otherwise have been incurred. From an economic efficiency standpoint, imports enable energy providers from outside the province to compete and displace more expensive domestic suppliers to meet Ontario's electricity needs at the lowest cost. Equally, exporters reduce the operational system cost by taking surplus energy out of Ontario when demand is low. This brings in revenue to cover fixed costs and avoids curtailing wind resources, spilling water at hydroelectric stations and maneuvering of nuclear units. Without exports, Ontario consumers would have to pay for the cost of the foregone energy that is spilled or curtailed. Between 2017 and 2020, this would likely have added $150-240 million per year[18] to Global Adjustment which would be recovered from domestic consumers.

As can be seen from Table 1, revenue from the ETS is only one component of the value that Ontario receives from exports and historically has been the smallest component of the economic benefits associated with exports. As such, it is important to consider the implications of increasing the ETS rate for exports on the other economic benefits that exports provide for Ontario consumers.

The Intertie Congestion Price

There is a maximum quantity of energy that can be transacted over a specific intertie at one time due to the physical limitations of the respective intertie. As noted above, electricity trading over the interties is a competitive marketplace driven by profit-seeking traders transacting based on the expected electricity price differences between jurisdictions. These factors make intertie capacity a scarce resource resulting in traders competing for access to these resources.

When there is more export demand than available intertie capacity, exporters compete for scarce intertie capacity by paying the ICP – a premium based on their willingness-to-pay. The ICP is set hourly based on competitive trader bids indicating how much they would be willing to pay to export over the intertie for a specific hour. The highest bids are accepted to export over the intertie during the given hour. This willingness-to-pay approach of the ICP means intertie access to flow exports is fairly allocated to the competitive traders who value the export service highest for the given time period.[19]

An important feature of the ICP is that it is dynamic and automatically adjusts with the value of the intertie capacity, which itself is dependent upon hourly market conditions. If hourly wholesale market prices are expected to be lower in Ontario relative to its neighbouring jurisdictions, traders will

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[16] ETS collected 2017-2020. For further details, see Table 1
[17] Uplifts collected from exporters 2017-2020. For further details, see Table 1
[18] Average of avoided curtailments through exports 2017-2020. For further details, see Table 1
[19] Exports are scheduled on an hourly basis

compete against one another by bidding up the price for intertie access relative to expected profit conditions. Increased competition and willingness-to-pay to flow the electricity out of Ontario will increase the ICP for which exports are charged.

For example, the ICP on the intertie to Michigan (where there has historically been high demand to export) averaged $19/MWh[20] in 2017 while annual prices on the Minnesota and New York interties are in the range of $7-9/MWh.

Market Design Changes

Revenues from the ICP are collected by the IESO in the Transmission Rights Clearing Account (TRCA). In addition to ICP revenue, the TRCA also contains revenue from Transmission Rights (TR) auctions. TRs are a financial contract that entitle their holder to a share of the ICP revenue on the intertie specified in the contract. TRs do not involve any use of the physical transmission system, and do not entitle the purchasers of the rights to utilize the transmission assets. By purchasing a TR, the TR holder gains insurance against changes in the ICP on the specified intertie (which can be unpredictable and volatile).

The IESO pays the TR holders from the ICP revenues. Revenues from the TR auction plus any residual ICP revenues after payments to TR holders are disbursed, subject to a TRCA balance threshold, on a semi-annual basis to domestic consumers and exporters to offset transmission costs.

As shown in Table 2, approximately $160 million per year has been paid out in disbursements since 2017.

Table 2: TRCA Historical Flows 2017-2020

$Millions	2017	2018	2019	2020	Average
Total Allocated TR Auction Revenues	153	156	136	93	134
Congestion Rents Received from the Market[21]	219	208	137	105	167
Interest earned on TR Bank Account	1	2	3	1	2
Payments to TR Rights Holders	(206)	(173)	(135)	(86)	(150)
TR Clearing Account Disbursement[22]	(173)	(188)	(149)	(118)	(157)

Source: IESO Power Data (https://www.ieso.ca/en/Power-Data/Monthly-Market-Report)

As part of the OEB's 2012 ETS Decision[23], the OEB expressed uncertainty as to the extent to which ICP revenues defray domestic consumer costs and, as the IESO acknowledged, this uncertainty meant the zero ETS rate would result in increased consumer costs unless ICP revenues were allocated to consumer costs.

[20] Based on ICP prices on the Michigan intertie which averaged $19/MWh in 2017

[21] Includes congestion rents received from both Export and Import

[22] The TRCA disbursements do not clear the TRCA balance due to a combination of a) maintaining the reserve threshold as defined in Chapter 8, section 4.18 of the Market Rules, and b) time-lag between collection of revenues from Congestion Rents and TR Auctions and disbursement

[23] EB-2012-0031 Decision and Order, June 6, 2013

The IESO is continuously improving and evolving the wholesale electricity market to ensure system reliability, resilience, and efficiency to meet the system needs. Since the 2012 CRA Analysis was performed, the IESO has implemented a number of market design changes that provide greater transparency and certainty as to how revenues are collected from exporters through the ICP and disbursed through the TRCA. These recent market design changes are summarized below:

- **Transmission Rights[24] Review (effective from 2015):** the Transmission Rights (TR) Review introduced a new methodology to refine the quantity of TRs auctioned ensuring revenues were balanced. As a result, starting in 2015 significantly higher amounts of intertie congestion funds were available to be disbursed to domestic consumers and exporters from the TRCA on a semi-annual basis.[25] This was followed by a market rule amendment that extended the period over which the disbursements were assessed to improve fairness.[26]

- **TRCA Disbursement Methodology (effective from 2021):** historically, disbursements from the TRCA were made based on volumetric consumption. The IESO adopted a recommendation from the OEB's Market Surveillance Panel to allocate TRCA surplus disbursements based on proportion of transmission service charges paid.[27] The design change will ensure that a greater portion of TRCA disbursements are returned to domestic load, compared to other market participants such as exporters. Based on historical estimates, disbursements of TRCA surplus funds to domestic load will increase between 87-98%.[28]

These market design changes mean the vast majority of funds disbursed through the TRCA reduce transmission costs for domestic consumers. Further, it should be noted that the dynamic nature of the ICP and design changes made to the TRCA are aligned with wider IESO initiatives, including the Market Renewal Program[29], to ensure Ontario has a dynamic market that delivers transparent and competitive outcomes.

4. Market Implications of an Increased Export Transmission Service Rate

Increasing the ETS from its current rate risks increasing the transaction costs of exporting energy which is likely to reduce the volume of economically efficient exports and have a negative impact both in terms of operational and economic benefits provided by exports. From an operational perspective, less exports would reduce the flexibility to balance the system and adversely impact the ability for exports to provide other services to help maintain grid stability. From an economic standpoint, exports contribute between $330-520 million per year[30] to Ontario that directly reduce transmission costs for domestic consumers and help avoid the cost of forgone energy to balance the

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24 Transmission Rights provide the holder with insurance against changes in the ICP

25 TR Auction Process Update, SE-110 – Webinar, December 12, 2016

26 See IESO Market Rule Amendment Proposal MR-00421, September 18, 2015

27 TRCA Disbursement Methodology – Vote to Post, IESO Technical Panel, May 26, 2020

28 TRCA Disbursement Methodology – Vote to Post, IESO Technical Panel, May 26, 2020, pg. 8

29 For more information on the IESO Market Renewal Program see: https://www.ieso.ca/en/Market-Renewal

30 Range of total value from exports 2017-2020. For more details, see Table 1

grid. Any increase in ETS from its current rate will likely reduce the value to ratepayers of exports using the interties, which in turn will result in higher system costs that would need to be recovered from domestic consumers.

The 2021 Elenchus Report presents three ETS rate options based on different cost allocation methodologies ($6.54/MWh, $3.66/MWh, and $5.42/MWh respectively). Each ETS rate option represents a significant increase over the approved 2020 ETS rate of $1.85/MWh and is outside of the historical range for the ETS rate ($1-2/MWh). In light of the options presented in the 2021 Elenchus Report, the IESO has focused its analysis on the market implications of an increased ETS rate.

The IESO expects that any increase in revenue resulting from a higher ETS would be offset by an equivalent reduction in revenue from the ICP, which in turn will decrease the amount that is disbursed from the TRCA to Ontario consumers. Intertie trade is driven by expected hourly price differences between electricity markets so exporters are highly sensitive to costs as it directly impacts profit margins. As noted above, exporters must pay the ICP in addition to ETS whenever they flow electricity over a congested intertie. The ICP and ETS are both transaction costs that negatively impact the profit margins of competitive intertie trade. This means that, if wholesale price differences between markets are held constant, the ICP and ETS have an offsetting relationship such that an increase in the ETS will lead to a proportionate decrease in the ICP. This offsetting relationships means that, assuming the quantity of exports remains constant, the overall value that Ontario ratepayers derive from exports would remain unchanged even if the ETS rate is increased.

In addition to decreasing ICP revenue, a higher ETS could have the effect of reducing energy exports from Ontario and by extension the operational and economic benefits that those lost exports provide. In contrast to the dynamic nature of the ICP, the ETS is a fixed charge applied on all exports regardless of market conditions. This means there will be occasions when market conditions are such that the ETS charge will make exports uneconomic and prevent an otherwise economic export from transacting.

The impact of a higher ETS on the Ontario market can be explored by the following two scenarios:

- **Wide price spread between markets:** occurs when there is a wider difference, or 'spread', between the price to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario an increase to the ETS will result in an offsetting decrease in ICP but no impact to export flows. As an example, if the expected price spread was $20, ETS was $2, Uplift was $1 and the ICP was $16, then a $2 increase in ETS would likely result in an offsetting $2 decrease in ICP.
- **Tight price spread between markets:** occurs when there is less price difference to buy electricity in Ontario and sell electricity in neighbouring jurisdictions. In this scenario the tighter price spread means there will be less demand to export, and therefore the ICP will be less to start with. As a result, there will be less or no ICP to offset an increase to the ETS. This means exports will become uneconomic on basis of a smaller increase in ETS compared to the wide price spread scenario. As an example, if the price spread was $5, ETS was $2, Uplift was $1 and the ICP was $1, then a $2 increase in ETS to $4 would stop the trade as even if ICP went to $0, there would still be no profit incentive for the exporter to transact. When exports do not flow, no ICP, ETS or Uplift revenues are collected to defray domestic consumer system costs. In this respect it can be understood that export flows are more sensitive to increases in ETS under a tight price spread than under a wide price spread. It also

means more exports will be prevented under the tight price scenario, and so have a greater negative economic and operational impact.

The tight price spread scenario illustrates the risk of reduced exports in the event of a higher ETS rate. The magnitude of economic exports reduced by increased ETS will ultimately be dependent upon the level of the ETS and the price spread between Ontario and neighbouring jurisdictions. At this time, the IESO has not undertaken a quantitative analysis to estimate the impact of a higher ETS rate on exports; however, even a relatively small increase in the ETS rate beyond the historical range of $1-2/MWh could have a material impact on heavily traded interties where price margins are already small. The 2012 CRA analysis demonstrates that in one case increasing the ETS rate from $0 to $5.80/MWh would cause a 50% reduction in export volumes (expressed as a percentage of status quo volumes)[31].

Fewer exports will have a negative operational impact across a number of areas, foremost in reducing the flexibility that interties provide to efficiently balance the grid in the course of normal system operations, surplus baseload management and unexpected events. Furthermore, less exports will reduce the role that interties can play in supporting regional reliability and diversification. This is likely to become increasingly important as the system evolves with the growth of more intermittent and distributed energy resources.

From an economic standpoint, exports contribute between $330-520 million per year[32] to Ontario that directly reduces transmission costs for domestic consumers and helps to avoid the cost of forgone energy to balance the grid. This benefit is detailed above. A reduction in exports would negatively impact the revenue collection and increase costs for domestic consumers in several ways including:

- **Congestion revenues:** Reduced exports would reduce congestion on the interties and the revenues that the IESO collects from congestion, which in turn is likely to reduce TRCA disbursements which, as noted above, have averaged $160 million per year since 2017.[33] The majority of these disbursements have gone to domestic consumers. Less exports would mean reduced TRCA disbursements and so increased transmission costs for domestic consumers.
- **ETS and Uplift:** Similar to congestion revenues, less exports would mean a reduced contribution from exports to system costs. Collectively exports contribute between $70 and 90 million per year in ETS and Uplift.[34] Many of these system costs would remain, regardless of exports and so the cost would have to be recovered from domestic consumers.
- **Avoided System Costs:** Exporters flow surplus energy out of Ontario when demand is low, which brings in revenue to cover fixed costs and avoids curtailing wind, spilling water at hydroelectric stations and maneuvering of nuclear units. Without exports these resources would have to be paid for their foregone energy, likely adding between $150-240 million per year to system costs which would have to be recovered from domestic consumers through increased Global Adjustment.[35]

[31] IESO internal analysis based on data presented in Export Transmission Service (ETS) Tariff Study, Charles River Associates, May 16, 2012, Pg. 18-20

[32] Range of total value from exports 2017-2020. For more details, see Table 1

[33] Average of TRCA disbursements 2017-2020. For more details, see Table 2

[34] Range of ETS and Uplifts 2017-2020. For more details, see Table 1

[35] Range of Avoided curtailments through Exports 2017-2020. For more details, see Table 1

The ICP and ETS are closely linked meaning that even a relatively small increase in ETS beyond the current rate could materially reduce export volumes on some heavily traded interties where price margins can be slim. In response, the IESO may need to curtail output from domestic baseload generators, such as hydroelectric, variable generation and potentially nuclear production. These actions would be highly undesirable, both from a financial and operational perspective, and likely result in increased costs for domestic consumers. Furthermore, a higher ETS would directly and negatively impact the amount of ICP revenue collected and reduce the total revenue currently returned to Ontario consumers.

5. Jurisdictional Comparison

In response to OEB direction in the EB-2019-0082 proceeding, Hydro One engaged CRA to prepare a jurisdictional review that compares the Ontario ETS rate to tariffs in neighbouring jurisdictions[36]. The 2021 Elenchus Report also contains a review of cost allocation methodologies used in other North American jurisdictions.

A review of export tariffs in other jurisdictions may suggest Ontario's ETS rate of $1.85/MWh is low and misaligned compared to other regions. However, it is important to consider other factors when comparing ETS in other jurisdictions.

First, as noted above, the ETS is just one component of the total charges on exporters, with other charges including ICP and Uplifts. Combining these charges means total revenues collected from exporters in Ontario is far higher than the $1.85/MWh ETS rate (for example, the ICP alone has recently averaged $7-15/MWh[37]). When comparing jurisdictions, it is important to consider all-in costs which reflect that Ontario collects significant revenues from exporters through the ICP in addition to the ETS.

Second, it is important to consider the benefits of Ontario's ICP design that dynamically adjusts to market conditions, compared to the 'point-to-point' model in many other US jurisdictions where exporters gain access to flow on a first-come, first-serve basis. In contrast to the ICP, the point-to-point model limits the collection of greater revenues beyond the ETS rate, even if exporters are willing to pay more. In this respect it can be seen that the ICP is a more effective mechanism with its fair allocation of access and dynamic adjustment to market conditions.

6. Pole Attachments Methodology

The interdependent relationship of the ETS with the willingness-to-pay and dynamic aspects of the ICP are important to recognize when considering the appropriateness of using the OEB's pole attachment approach for setting the ETS rate.

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[36] EB-2021-0110, Exhibit H-09-01-02

[37] Average ICP across interties with Michigan, Minnesota and New York, 2017-2019

While both exporters and pole attachers are seeking to use installed infrastructure – transmission lines for exports and telecom wires for pole attachers – there are importance differences in usage that require alternative approaches to revenue collection.

In the case of exporters, their marginal costs and willingness-to-pay varies hour-to-hour with market conditions as detailed above. Pole attachers by contrast make infrastructure usage decisions based on multi-year, fixed investments. In this context it can be seen that the dynamic approach of the ICP, which adjusts to reflect the changing marginal costs and willingness-to-pay of exports is more appropriate than the fixed rate approach used for pole attachers.

7. Conclusion

Through this submitted evidence, the IESO provides an update to the OEB on past uncertainties related to how ICP defrays consumer costs. Since the 2012 OEB ETS Decision, the IESO has made market design changes that clarify the role of ICP and has disbursed significant revenues back to domestic consumers through reduced transmission costs.

Exporters contribute to the cost of the Ontario transmission system through two mechanisms. The first mechanism is through the fixed ETS rate and the second mechanism is through the dynamic ICP mechanism. When considered together, exporters not only contribute approximately $30-40 million per year towards the transmission system through the ETS rate but have also paid an average of $160 million per year towards the cost of the transmission system from the ICP mechanism.

Interties with neighbouring jurisdictions provide a range of operational benefits and enhance system reliability for Ontario consumers. In operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions. Ontario exports electricity to neighbouring jurisdictions when it is surplus to domestic needs and economic to recover the operational cost of generation. Exports provide Ontario with critical operational and economic benefits to help the IESO reliably operate the grid and reduce system costs for domestic consumers.

Intertie trading is highly competitive and is driven by price spread opportunities between jurisdictions that fluctuate on an hourly basis. As a result, export transactions are highly price sensitive and transaction costs deter economically efficient trade. A higher ETS rate increases the transaction costs of exporting energy and will lead to fewer economically efficient trades, which in turn reduces the benefits that exports provide to the grid. A higher ETS rate would reduce trade volumes and ICP revenue, resulting in less efficient outcomes. Under some market conditions, even a relatively small increase in ETS could materially impact exports and require the IESO to curtail and spill output from domestic generators. These actions result in higher costs for domestic consumers.

In summary, when setting the ETS, consideration should be given to maximizing the operational and economic benefits provided by exports by minimizing transaction costs. Any increase in the ETS rate will reduce the value of interties, leading to less system flexibility to reliability manage the grid and higher costs for Ontario consumers.

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