Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

BY EMAIL

September 6, 2022

Ms. Nancy Marconi
Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4
Registrar@oeb.ca

Dear Ms. Marconi:

Re: Ontario Energy Board (OEB) Staff Submission
Generic Hearing on UTR Issues
Export Transmission Service Rate
OEB File Number: EB-2021-0243

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 3.

Yours truly,

Michael Price Digitally signed by Michael Price Date: 2022.09.06 11:01:23 -04'00'

Michael Price
Senior Advisor, Generation & Transmission

Encl.

cc: All parties in EB-2021-0243

ONTARIO ENERGY BOARD

OEB Staff Submission

Generic Hearing on UTR Issues

Export Transmission Service Rate

EB-2021-0243

September 6, 2022

1. Background and Overview

1.1 Overview of the Proceeding

The Ontario Energy Board (OEB) established a generic public hearing on its own motion under sections 19, 21 and 78 of the *Ontario Energy Board Act, 1998* (OEB Act) to consider various issues related to Ontario's Uniform Transmission Rates (UTR).

The first phase of the hearing has focused on reviewing and setting the Export Transmission Service (ETS) rate. Other UTR-related issues will be considered in a subsequent phase or phases of the hearing.

1.2 Overview of OEB Staff Submission

OEB staff submits that the OEB should continue to apply an ETS rate for export service and that the ETS rate should be set using the cost-based approach outlined by Elenchus Research Associates Inc. (Elenchus) in this proceeding.

OEB staff submits that the Elenchus Curtailment Model scenario is an appropriate starting point for setting the ETS rate. That scenario would result in an ETS rate of $5.42/MWh, after adjustments to account for the Network Pool revenue requirements of all Ontario transmitters.

OEB staff submits that an increase to the ETS rate should be phased-in over a period of time to mitigate rate impacts to the export class, to allow for continued assessment of electricity market and operability implications of an ETS rate increase, and to recognize uncertainties around market participant behavior change, market renewal implementation, and technology change.

OEB staff recommends retaining the current $1.85/MWh ETS rate for all of 2023, increasing the ETS rate to $2.15/MWh starting in 2024, and then continuing to increase it each year by approximately $0.30/MWh until it reaches $3.66/MWh in 2029.

OEB staff recommends convening a review of ETS rate performance in 2029, after the $3.66/MWh rate has been reached. The review would address matters that the OEB deems relevant, including whether the OEB should continue to increase the ETS rate to $5.42. If the OEB were to consider it appropriate to continue with the phased-in increase, the ETS rate could then continue to increase at the $0.30/MWh annual rate to reach the proposed rate of $5.42/MWh by 2035.

OEB staff submits that an electricity export monitoring and analysis program should be established to support future reviews of the ETS rate. The program should be led by an independent party. The ETS rate should be subject to an annual inflation adjustment once it reaches $5.42/MWh, or sooner as the OEB sees fit, and it should be reviewed in some detail every ten years. Given that this is the first full cost based review of the ETS rate, OEB staff recommends that the next cost based review occur in 2029 at which time the OEB can also consider a framework for any inflationary adjustments going forward, any interim reviews and to confirm the ten year rate plan.

2. OEB Staff Submission

Issue 1: Is it appropriate to continue to rely on an Export Transmission Service (ETS) rate and on Intertie Congestion Pricing (ICP) to charge for export service?

Submission:

1a. OEB staff submits that it is appropriate to continue to rely on an ETS rate and on ICP to charge for export service. The ETS rate and ICP serve different functions and their revenues serve to offset different costs.

Discussion:

Function of the ETS rate: The ETS rate is a fixed rate set by the OEB and is applicable "for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario".[1] In other words, the ETS rate is a charge paid by exporters for their use of the Ontario transmission system, including for exports and wheel-throughs.

Function of ICP: The ICP is administered by the Independent Electricity System Operator (IESO) to allocate access to interties when there is more demand than capability through the use of a dynamic pricing mechanism that automatically adjusts to changing market conditions.[2] The ICP reflects the real-time value of transmission access based on competition (exporters' willingness to pay for access) and market conditions in Ontario and neighbouring jurisdictions.[3]

Flow of ETS revenue: ETS revenue reduces the transmission revenue requirement that is recovered from Ontario transmission-connected end-use customers and distribution end-use customers.

ETS revenue is collected by the IESO from exporters based on the OEB-approved ETS rate and is remitted to Hydro One Transmission (Hydro One). The ETS revenue is treated as "Other Revenue" and is applied as a reduction to Hydro One's transmission revenue requirement for the Network rate pool. Hydro One's transmission revenue requirement allocated to the Network rate pool is an input to the total Ontario Network Pool UTR.

ETS revenue flows to customers through a reduction of Network Pool UTR for Transmission-connected end-use customers, or through a reduction to Network Retail

[1] EB-2021-0276, 2021 Ontario Uniform Transmission Rate Schedules, p. 6
[2] EB-2021-0243, Exhibit JT-1.3, p.8
[3] EB-2021-0243, Exhibit I/Tab 1/Schedule 34, (g)

Transmission Service Rates (RTSR) for distribution customers.[4]

Flow of ICP revenue: ICP revenue reduces wholesale market service charges that are recovered from market participant end-use load customers and distribution end-use customers.

ICP revenue is returned to customers as an energy market uplift payment as part of the Transmission Rights Clearing Account (TRCA) Disbursement.

The TRCA account consists of the congestion rents collected via the ICP as well as the proceeds from the Transmission Rights Auction. Withdrawals are made from the TRCA to make monthly payouts to Transmission Rights holders. The IESO reviews the TRCA balance on a semi-annual basis and disburses the surplus funds when the balance exceeds the reserve threshold of $20M by at least $5M; or as directed by the IESO Board.

Any TRCA surplus is first divided between Ontario load and exporter classes based on the proportion of total provincial transmission service charges and total export transmission service charges collected from the market during the preceding six months. After the TRCA surplus is divided between loads and exporters, the members of each class are then settled based on the proportion of energy withdrawn over the preceding six months or as directed by the IESO Board.

TRCA disbursement payments flow to customers through a wholesale market service credit amount on an IESO settlement statement (for a market participant) or through reduced wholesale market service charges (for a non-market participant distribution customer). Wholesale market service charges (or uplifts) are "out-of-market costs incurred to operate the power system reliably".[5] They include Congestion Management Settlement Credits, Intertie Offer Guarantees and others.

Electricity distributors record TRCA disbursement payments (credit to customers) in a deferral and variance account - Account 1580 (Wholesale Market Service Charges). Whenever an electricity distributor disposes of the balance in Account 1580 (typically on an annual basis), the TRCA disbursement payments flow to its distribution customers who are not wholesale market participants as an offset to the wholesale market service costs that the electricity distributor passes through to them.[6]

In summary, OEB staff submits that ETS rates and ICP do different things, and that their revenues offset different types of costs paid by Ontario customers. Fixed ETS rates recover transmission costs from exporters while the variable ICP mechanism allocates access to interties. ETS rate revenue reduces Ontario's transmission revenue

[4] EB-2021-0243, Exhibit JT-1.3 provides a more detailed and thorough overview of ETS revenue disbursement
[5] EB-2021-0243, Exhibit I/Tab 3/Schedule 10, Interrogatory response to Pollution Probe 10b and 10c
[6] *Ibid*.

requirement, while ICP revenue reduces wholesale market service charges. One is not a substitute for the other; it is therefore appropriate to continue to rely on both.

Issue 2: If an ETS rate were to continue to exist alongside ICP, what approach should be used to set the ETS rate?

<u>**Submission**</u>

2a. OEB staff submits that it is appropriate to set the ETS rate using a cost-based approach. By "cost-based approach", OEB staff refers broadly to a methodology that accounts for transmission revenue requirements and their appropriate allocation.

2b. OEB staff further submits that the cost-based approach outlined by Elenchus in this proceeding is appropriate for setting the ETS rate.[7]

2c. OEB staff submits that the Elenchus "Allocation on Basis of 80% of Shared Net Fixed Assets" scenario is an appropriate starting point for setting the ETS rate. That approach would result in an ETS rate of $5.42/MWh, after adjustments to account for the Network Pool revenue requirements of all Ontario transmitters.

2d. OEB staff submits that while the "Allocation on Basis of 80% of Shared Net Fixed Assets" scenario is an appropriate cost-based starting point for setting the ETS rate, other factors should be considered when setting and implementing an increase to the ETS rate. Those other factors are discussed by OEB staff under issue 3.

<u>**Discussion:**</u>

2a. A cost-based approach for setting the ETS rate offers the following advantages:

Fairness: a cost-based approach is fair because it aligns with cost causality principles. In the case of the ETS rate, a cost-based approach aligns with the principle of "user pay" or "no free rider": it assigns costs to those who use the Ontario transmission system in proportion to their use of it. Elenchus has echoed this point by suggesting that even though export demand needs do not drive power system reliability planning assessments and design, "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."[8]

Transparency: a cost-based approach for setting the ETS rate relies on inputs that are generally available, and which are accessible by the public (e.g., revenue requirements, export forecasts, ETS setting methodology). It also involves a rate-setting process that is public, participatory and which allows for scrutiny of evidence and arguments.

[7] EB-2021-0243, Submissions on the ETS Rate, Attachment 1: Export Transmission Service Rate Cost Allocation Methodology (The 2021 Elenchus Report)
[8] *Ibid*. p. 2 (6 of 44)

Precedent in other jurisdictions: a cost-based approach for setting ETS rates is not novel: it is used by others. This is illustrated in the survey of ETS rates in other jurisdictions that Charles River Associates (CRA) conducted in this proceeding.[9] CRA found that ETS rates are generally cost-based in the US jurisdictions that it surveyed. That is, they are generally designed to recover total annual transmission revenue requirements over forecasted annual transmission billing units.

CRA noted that in the US, this rate design stems from FERC rate principles that provide open and non-discriminatory access to transmission users and contemplate reasonable opportunity for transmission owners to recover costs.[10] As part of its survey, CRA also did not find any rate-setting approach used for export rates that sought a specific market outcome, such as encouraging or discouraging exports.[11]

Similarly, Elenchus noted in its own survey that the Régie de l'énergie in Quebec has a long-standing "no free service" guiding principle for cost allocation and rate design and that the first cost allocation principle of FERC Order No. 1000, which addresses cost allocation with respect to new transmission facilities, is that "costs should be allocated in a way that is roughly commensurate with benefits".[12]

In keeping with previous OEB interest in a cost-based ETS rate: The OEB has expressed interest in a cost-based ETS rate since at least 2013. For example, in its Decision and Order on the 2013 ETS rate, which was reviewed in Hydro One's 2013-2014 transmission rates application proceeding, the OEB directed Hydro One to "prepare a cost allocation study involving the network assets utilized by export transmission customers and report the results of this study, including a proposal of the appropriate cost based ETS rate with supporting rationale, to the Board at its next transmission rates application."[13] Hydro One filed that study in 2014.[14]

More recently, in its Decision and Order on Hydro One's 2020-2022 transmission rates application, the OEB "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates". In that same Decision and Order, 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 Hydro One's next transmission rebasing application.[15] Hydro One filed that study in its 2023-2027 transmission rates application: it is the 2021 Elenchus Report that has been extracted from Hydro One's 2023-2027 rates proceeding for review in this proceeding on the ETS rate.

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[9] EB-2021-0243, Submissions on the ETS Rate, Attachment 2: Jurisdictional Review of Export Transmission Service (ETS) Rates Study (The CRA Report)
[10] EB-2021-0243, Presentation Day Materials, KP1.3: CRA Presentation
[11] EB-2021-0243, Presentation Day Materials Transcript, pp. 57-58
[12] EB-2021-0243, Presentation Day Materials, KP1.2: Elenchus Presentation
[13] EB-2012-0031, Decision and Order on 2013 Export Transmission Service Rates, June 6, 2013, p. 10
[14] EB-2014-0140, Exhibit H1-5-1, Attachment 1
[15] EB-2019-0082, Decision and Order, Hydro One 2020-2022 Transmission Rates, April 23, 2020

The existing ETS rate of $1.85/MWh was first established in Hydro One's 2015-2016 Transmission Revenue Requirement proceeding.[16] All parties in that proceeding agreed to an ETS value of $1.85/MWh for the purpose of reaching a settlement. The settlement agreement was approved by the OEB in 2014 and established the ETS rate for 2015 and 2016.[17] The OEB subsequently approved the continuation of the ETS Rate at $1.85/MWh for 2017 and 2018[18], for 2019[19], and for 2020 to 2022.[20]

2b. OEB staff further submits that the cost-based approach presented in the 2021 Elenchus Report is appropriate for setting the ETS rate. As described below, OEB staff considers the Elenchus methodology to be reasonable.

Functionalization: OEB staff takes no issue with Elenchus' identification, performed in consultation with Hydro One, of assets and costs associated with export and other activities. OEB staff also takes no issue with how Elenchus characterized assets and costs as either Dedicated to Domestic, Dedicated to Interconnect, or Shared.

Classification: OEB staff takes no issue with Elenchus' treatment of all relevant assets and costs as demand-related.

Allocation of shared costs: Shared assets are those that serve both domestic and export customers, including assets associated with generation connection.[21] OEB staff supports Elenchus' allocation of Shared Network Asset-related costs and OM&A expenses between domestic and export customers. This is a change in methodology from the previous 2014 Elenchus Report, in which asset-related costs associated with shared assets were not allocated to exporters (they were fully allocated to Ontario domestic customers, instead).

The change in the current 2021 Elenchus Report towards allocating some OM&A expenses and Shared Network Asset-related costs to exporters is appropriate as it reflects how the transmission system is currently used by exporters, in OEB staff's view. It is consistent with the "user pay" or "no free riders" principle, which holds that there should not be users of a shared network that do not pay their fair share of costs for the use of that network. While the transmission system was not designed for exporters, exporters use the system and benefit from it. They should pay for some of it accordingly.

OEB staff also notes that the allocation of some Shared Network Asset-related costs to exporters is consistent with the approach described in the Report of the Board on Pole Attachments, in which the OEB considered the value that users obtain from leveraging

[16] EB-2014-0140
[17] Ibid., Oral Hearing Settlement Presentation Transcript, Vol. 1. December 2, 2014, p. 28
[18] EB-2016-0160
[19] EB-2018-0130
[20] EB-2019-0082
[21] EB-2021-0243, Submissions on the ETS Rate, Attachment 1: Export Transmission Service Rate Cost Allocation Methodology (The 2021 Elenchus Report), p. 11 (15 of 44)

an established network.[22] The report stated that the OEB will move forward with allocating some portion of common costs, which are analogous to shared costs, to third party attachers while continuing to assign responsibility to third party attachers for their direct costs.[23]

Allocation of interconnection costs: OEB staff supports Elenchus' proposal to allocate interconnection costs between domestic customers and export customers. This is a change in methodology from the 2014 Elenchus Report, in which interconnection costs were allocated to exporters only. This is a benefit to export customers. OEB staff accepts Elenchus' reasoning that "a portion of interconnection assets, asset-related costs, and OM&A should be allocated to the Domestic class" because interconnections serve both exporters and Ontario domestic customers.[24]

OEB staff notes that some imports into Ontario are consumed by Ontario domestic customers while some leave the province as wheel-throughs. While this was not accounted for in the proposed allocation of interconnection costs between Ontario domestic customers and exporters, OEB staff suggests that it could be a subject for future refinement, subject to other priorities.[25] OEB staff notes that wheel-throughs represent a "relatively small share of the total volume" of import transactions.[26] The impact of any such refinement would probably not be material.

Allocation of external revenues: OEB staff supports Elenchus' proposal to allocate some external revenues to export customers. This would represent a benefit to export customers. This is another change in methodology from the 2014 Elenchus Report, in which no portion of external revenues was allocated to exporters. OEB staff accepts Elenchus' reasoning that "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 [Hydro One] related to the use of those assets."[27]

Allocation of domestic costs: OEB staff takes no issue with Elenchus' direct allocation of Dedicated to Domestic assets, asset-related costs, OM&A, and external revenues solely to the domestic Ontario class (e.g., transformation, line connection, line connection portion of dual function lines).

Coincident Peak allocators: OEB staff takes no issue with Elenchus' use of the 12 Coincident Peak (12 CP) allocator as a basis for allocating transmission system costs between domestic and exporter classes. OEB staff accepts Elenchus' point that "1 CP

[22] EB-2015-0304, Report of the Ontario Energy Board, Wireline Pole Attachment Charges
[23] *Ibid*., p. 33
[24] EB-2021-0243, Submissions on the ETS Rate, Attachment 1, The 2021 Elenchus Report, p. 25 (29 of 44)
[25] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, p.152, lines 18-20
[26] EB-2021-0243, Technical Conference Transcript Day 1, July 28, 2022, p.92, lines 3-7
[27] EB-2021-0243, Submissions on the ETS Rate, Attachment 1, The 2021 Elenchus Report, p. 29 (33 of 44)

could vary considerably from year to year depending on the month the transmission system peak occurs", whereas 12 CP is "considerably more consistent over time.[28]

OEB staff accepts Elenchus' proposal to allocate assets and expenses that are categorized as Dedicated to Interconnect by the Intertie 12 CP between Domestic and Export class. OEB staff also accepts Elenchus' proposal to allocate Shared Network Asset-related costs and expenses using the Shared Net Fixed Assets 12CP, excluding assets Dedicated to Domestic and Dedicated to Interconnect. OEB staff also takes no issue with Elenchus' proposal to use the same Shared Net Fixed Assets 12CP allocator to allocate External Transmission Revenues.

2c. OEB staff submits that the Elenchus "Allocation on Basis of 80% of Shared Net Fixed Assets" scenario is an appropriate starting point for setting the ETS rate. That approach would result in in an ETS rate of $5.42/MWh, which includes adjustments to account for the Network Pool revenue requirements of all Ontario transmitters.

Three cost-based scenarios: The 2021 Elenchus Report outlined three cost-based scenarios or options to allocate Shared Network Asset-related costs between the domestic class and export class. They differ according to whether, and to what extent, they adjust or discount the proportion of Shared Network Asset-related costs that are allocated to the export class.

Scenario 1: The first scenario, known as the "Fully Allocated Model" scenario, allocates Shared Network Asset-related costs using an unadjusted (unreduced or undiscounted) 12CP export allocator. The unadjusted export allocator implicitly captures curtailments to export demands that may have occurred during the coincident peak periods that were included in the 12CP calculations. Elenchus stated that the unadjusted 12CP allocation of 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".[29] The Fully Allocated Model scenario results in an ETS rate of $6.54/MWh, after accounting for the Network Pool revenue requirements of all Ontario transmitters.

Scenario 2: The second scenario, known as the "Hybrid Model" scenario, discounts the export demand 12CP allocator 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."[30] Elenchus stated that the 50% export 12CP reduction "is aligned with the Pole Attachment hybrid methodology cited by the OEB" in its Decision and Order which "determined that the use of shared network facilities by exporters needs to be considered in setting the ETS rates."[31] The Hybrid Model scenario results in an ETS

[28] *Ibid*. p. 14 (18 of 44)
[29] *Ibid*., p. 29 (33 of 44)
[30] *Ibid*., p. 2 (6 of 44)
[31] EB-2021-0243, Presentation Day Materials, KP1.2: Elenchus Presentation

rate of $3.66/MWh, after accounting for the Network Pool revenue requirements of all Ontario transmitters.

Scenario 3: The third scenario, known as the “Curtailment Model” scenario, discounts the export demand 12CP allocator by 20% based on the service curtailment that affected exports in recent years. Assuming that exports were curtailed 20% of the hours in recent years, the scenario adjusts export demands to 80% of their actuals. In this way, the scenario allocates Shared Network Asset-related costs to exporters on the basis of 80% of the actual export class 12CP over the period considered. Elenchus stated that the Curtailment Model approach “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”.[32] The Curtailment Model scenario results in an ETS rate of $5.42/MWh, after accounting for the Network Pool revenue requirements of all Ontario transmitters.

Different service for the export class: OEB staff submits that Scenario 3 (the Curtailment Model scenario) is an appropriate starting point for setting the ETS rate. The approach recognizes that the export class is different from the domestic class in an important way. That is, the export class receives a lower priority of service in the operational timeframe: it is a curtailable class. This means that the IESO would prioritize the needs of domestic loads in the operating timeframe above those of the exporters if it had to. For example, the IESO would curtail exports before curtailing Ontario loads in the event of shortage conditions or some other reliability issue affecting the province.[33] The IESO adds further perspective in the following explanation, which underscores that exports are treated differently than domestic load by the power system operator:

> 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.[34]

Fairness: In OEB staff’s view, the Curtailment Model scenario is consistent with the principle of fairness, which, among other things, holds that equal classes ought to be treated equally while unequal classes ought to be treated unequally. The export class receives a different, unequal, and ultimately lower level of service than the domestic

[32] EB-2021-0243, Submissions on the ETS Rate, Attachment 1, The Elenchus Report, p.3 (7 of 44)
[33] EB-2021-0243, Technical Conference Transcript Day 1, July 28, 2022, pp.177-180
[34] EB-2021-0243, Submissions on the ETS Rate, Attachment 1, The Elenchus Report, p.19 (23 of 44)

class in the operational timeframe. The Curtailment Model scenario acknowledges this difference in the level of service that the export class receives. In contrast, the Fully Allocated Model scenario does not explicitly or fully account for the different service offered to the export class overall, even though it does implicitly capture actual export class demand during the applicable 12CP periods, which may have included some curtailments.[35]

In addition to its consistency with the principle of fairness, OEB staff submits that the Curtailment Model scenario arithmetically accounts for export class curtailments in a reasonable way. That is, the scenario reduces the export 12CP allocation in proportion to the extent that exporters have been curtailed in recent years. For example, the IESO curtailed exports in 17% of hours in 2020 and in 24% of hours in 2021.[36] OEB staff considers the 20% reduction applied to the export 12CP allocator in this scenario to be a reasonable approximation of the recent frequency of export curtailments.

ETS rate vs. average grid rate in other jurisdictions: Based on its survey of ETS rates in other jurisdictions, CRA stated that it “did not identify any specific cost allocation methodology applied to design ETS rates that would seek to allocate costs between domestic and export service classes.”[37] Rather, CRA suggested that rates in the U.S. jurisdictions it surveyed were set on a grid-wide basis.[38] For example, CRA observed that in PJM[39], the ETS reflects the composite or average cost of service in the PJM region, under the principle that all other facilities are available to provide such service. CRA suggested that this is also the practice in other U.S. jurisdictions, such as New York ISO[40] and ISO NE.[41] CRA stated that in such jurisdictions, “for the purpose of deriving this rate, the costs are collected and bundled and summed together and divided by the either CP or MWh. So just by pure mathematics, it is a rate that applies to every user equally.”[42]

ETS rate vs. Network Pool rate in Ontario: Although exporters might pay the same transmission rates as domestic loads do in at least some of the U.S. jurisdictions that were surveyed by CRA, OEB staff submits that this would not be appropriate in the Ontario context. OEB staff is of the view that the export class ought to pay less than the average or composite cost of transmission service in Ontario. This means that the ETS rate ought to be lower than the Ontario Network Pool UTR. OEB staff submits that the export class ought to pay less than the Network Pool UTR because the export class

[35] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, p.154, lines 20-25
[36] EB-2021-0243, Exhibit I/Tab 1/Schedule 11, Interrogatory response to OEB staff 11
[37] EB-2021-0243, Presentation Day Transcript, August 4, 2022, p.154, lines 2-9
[38] *Ibid.*, p. 154
[39] PJM Interconnection, L.L.C. - Regional Transmission Organizaton serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia.
[40] NYISO-New York Independent System Operator serving New York State
[41] ISO-New England Inc.- Regional Transmission Organization serving Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont.
[42] EB-2021-0243, Technical Conference Transcript Day 1, July 28, 2022, pp. 75-76 lines 27-28, 1-2

receives a lower priority of service. Assigning the same Network Pool rate to the export class as to the domestic class, but for a lower level of service, would be unfair, in OEB staff's view.

OEB staff notes that the Curtailment Model scenario does result in an ETS rate that is lower than the current Ontario Network Pool UTR. This can be seen in Table 1, below, prepared by OEB staff. The table compares the current Network Pool UTR to the Curtailment Model scenario ETS rate, as well as to the current ETS rate across a range of capacity-to-energy load factor conversion assumptions.

Table 1: Comparison of the current ETS rate and the Curtailment Model Scenario ETS rate with the current Ontario Network Pool UTR

Row Ref.	Calculation (where applicable)	Description	Value
(a)		**Current Network Pool UTR monthly ($/kW)[43]**	$5.46
(b)		**Current Network Pool UTR monthly ($5.46/kW) converted to $/MWh assuming 100% load factor conversion**	$7.48
(c)		**Current Network Pool UTR monthly ($5.46/kW) converted to $/MWh assuming 49% load factor conversion (49% = 2021 export class average)**	$15.26
(d)		**Current ETS rate ($/MWh)[44]**	$1.85
(e)	(d)/(b)	**Current ETS rate ($1.85/MWh) as % of Current Network Pool UTR converted to $/MWh assuming 100% load factor conversion ($7.48/MWh)**	25%
(f)	(d)/(c)	**Current ETS rate ($1.85/MWh) as % of Current Network Pool UTR converted to $/MWh assuming 49% load factor conversion ($15.26/MWh)**	12%
(g)		**Curtailment Model ETS rate ($/MWh)**	$5.42
(h)	(g)/(b)	**"Curtailment Model" ETS rate ($5.42/MWh) as % of Current Network Pool UTR converted to $/MWh assuming 100% load factor conversion ($7.48/MWh)**	72%
(i)	(g)/(c)	**"Curtailment Model" ETS rate ($5.42/MWh) as % of Current Network Pool UTR converted to $/MWh assuming 49% load factor conversion ($15.26/MWh)**	36%

The current OEB-approved Network Pool UTR is $5.46/kW.[45] Restated on an energy basis[46] for comparison with the ETS rate, the current Network Pool UTR is $7.48/MWh, assuming a 100% load factor conversion.[47]

[43] EB-2022-0084, Decision and Rate Order, 2022 Uniform Transmission Rates Update, Schedule B, p. 5 of 6, April 7, 2022
[44] *Ibid.*, p. 6 of 6
[45] EB-2022-0084, Decision and Rate Order, 2022 Uniform Transmission Rates Update, Schedule B, p. 5
[46] Rather than on a capacity or demand basis
[47] EB-2021-0243, Exhibit I/Tab 1/Schedule 23, Interrogatory response to OEB staff 23
CRA stated that "use of a 100% load factor conversion is one industry convention used to convert a

CRA noted that the actual utilization of export flows averaged 49% of intertie capability in 2021, according to information provided by the IESO.[48] If this actual level of utilization was used in the load factor conversion instead of the more generic assumption of 100%, the current Network Pool UTR, restated in energy terms, would be $15.26/MWh.

OEB staff therefore suggests that the current, restated, Network Pool UTR is between $7.48/MWh and $15.26/MWh, depending on the load factor conversion. The lower value uses the most conservative load factor assumption of 100%, the higher value uses the actual load factor of export flows in 2021. In either instance, the Curtailment Model scenario ETS rate of $5.42/MWh is between 72% and 36% of the current Network pool UTR.

Therefore, at the Curtailment Model scenario ETS rate, the export class would be charged a rate that is from 28% to 64% lower than what Ontario domestic loads currently pay as the Network pool rate. The Curtailment Model scenario ETS rate is directionally consistent with OEB staff's submission that the export class ought to pay a rate that is lower than the Network Pool UTR to reflect the different level of priority service that the export class receives compared to the domestic class.

For additional context, OEB staff notes that the existing ETS rate of $1.85/MWh is 75% to 88% lower than the current Network Pool UTR as indicated in Table 1, depending on the load factor conversion. The export class already pays a sizeable discount compared to what Ontario loads pay for the Network Pool UTR. While the Curtailment Model scenario would increase the ETS rate, the rate would remain below the current Network pool rate that is paid by Ontario's domestic class.

For further perspective, OEB staff notes that the current ETS rate of $1.85/MWh appears to be lower than the export rates in the jurisdictions surveyed by CRA, while the Curtailment Model scenario rate appears to be less out of line with some of the rates reported by CRA.[49] That said, OEB staff appreciates CRA's observation that "the rate level and structure of ETS rates varies significantly across the jurisdictions reviewed" and that "many factors influence the resulting export rate or any network service rate on any system".[50] OEB staff further underscores CRA's statement that "it is difficult to draw

demand based rate to an energy based cost at an assumed load factor usage". CRA added that the result of the conversion "represents what a customer's unit costs would be under a demand charge if their usage were at a 100% load factor." CRA clarified that "actual load factor experience for any customer will of course be based on that customer's particular load profile" and that "if load factor used for conversion were lower [than 100%], MWh would be lower, and the resulting quotient in [the $/MWh result] would be higher". This means that the 100% load factor conversion provides the lowest possible estimate of a capacity-based rate converted to an energy-based rate.

[48] *Ibid*.

[49] EB-2021-0243, Exhibit I/Tab 1/Schedule 23, Interrogatory response to OEB staff 23

[50] *Ibid*.

any direct comparison" between the rates in the jurisdictions it surveyed and the Ontario ETS rate.[51]

To summarize, OEB staff submits that it is appropriate to set the ETS rate using a cost-based approach; that the cost-based approach outlined by Elenchus in this proceeding is appropriate for setting the ETS rate; and that the Curtailment Model scenario is an appropriate starting point for setting the ETS rate.

The Curtailment Model scenario, also known as the "Allocation on Basis of 80% of Shared Net Fixed Assets" scenario, accounts for the different level of service that the export class receives compared to the Ontario domestic class. The scenario results in an ETS rate of $5.42/MWh, after adjustments to account for the Network Pool revenue requirements of all Ontario transmitters. The rate is directionally consistent with OEB staff's view that, in fairness, the export class ought to pay a rate below the Network Pool UTR, given the lower priority service that the export class receives compared to the domestic class. The Curtailment Model scenario results in an ETS rate that is 28% to 64% lower than the current Network pool rate that is paid by the Ontario domestic class

Under the Curtailment Model scenario, the domestic class would be allocated 100% of the capital and operating costs of assets that are dedicated to domestic customers.[52] The export class would be allocated approximately 72% of the costs associated with interconnections (domestic customers would be allocated 28%).[53] The export class would also be allocated approximately 8.7% of shared asset costs (the domestic class would be allocated about 91.3% of shared asset costs).[54] Overall, the export class would be allocated approximately 5.7% of Ontario's total annual transmission revenue requirement under the curtailment model scenario, while the domestic class would be allocated approximately 94.3%.[55]

While the Curtailment Model scenario might be an appropriate cost-based starting point for setting the ETS rate, OEB staff submits that other factors should be considered when setting and implementing the ETS rate. Those factors are discussed below under Issue 3.

Issue 3: Are there other key issues the OEB should consider related to the ETS rate?

Submission

3a. OEB staff submits that electricity market and operability implications ought to be

[51] *Ibid*.
[52] EB-2021-0243, Exhibit I/Tab 1/Schedule 14, Interrogatory response to OEB staff 14
[53] Ibid.
[54] EB-2021-0243, Exhibit I/Tab 1/Schedule 16, Interrogatory response to OEB staff 16
[55] EB-2021-0243, Exhibit I/Tab 1/Schedule 17, Interrogatory response to OEB staff 17, p. 6

considered when setting and implementing an increase to the ETS rate.

3b. OEB staff submits that uncertainties related to future market participant behavior change, market renewal implementation, and technology change should also be considered.

3c. OEB staff submits that rate impacts to the export class should also be considered when implementing an increase to the ETS rate.

3d. OEB staff submits that an increase to the ETS rate should be phased in over a period of time to mitigate rate impacts to the export class, to allow for continued assessment of electricity market and operability implications of an ETS rate increase, and to recognize uncertainties around market participant behavior change, market renewal implementation and technology change.

3e. OEB staff submits that an electricity export monitoring and analysis program should be established to support future reviews of the ETS rate. The program should be led by an independent party.

3f. OEB staff submits that the ETS rate should be subject to annual inflation adjustment once it reaches a steady state following its phased-in increase implementation.

3g. OEB staff submits that the ETS rate should be reviewed every ten years, beginning in 2029, with OEB discretion to initiate interim reviews as necessary.

Discussion:

Electricity market implications: An increase to the ETS rate would increase ETS revenues, all else being equal. Increased ETS revenues would, in turn, reduce transmission revenue requirements to be recovered from Ontario ratepayers. While OEB staff supports an increase to the ETS rate on the basis of user-pay and fairness principles, OEB staff submits that electricity market implications ought to be considered when implementing an increase to the ETS rate.

Power Advisory's analysis in this proceeding identified key market implications to consider when setting the ETS rate. Power Advisory concluded that that "all else being equal, increasing the ETS rate increases the transactional cost of exporting energy from Ontario, results in less supply being exported, reduces congestion rents and increases curtailment of baseload supply."[56] Power Advisory also concluded that the net impact of higher ETS revenues, lower export volumes and revenues, reduced congestion rents and more baseload supply curtailments and curtailment costs, would be a negative impact on Ontario ratepayers.

Power Advisory estimated that increasing the ETS rate from $1.85/MWh to $6.54/MWh

[56] EB-2021-0243, Expert Report for the market impacts of changes to the ETS Rate, May 2022 (The Power Advisory Report), p. 9

(the Fully Allocated Model described above) would have increased the costs to be borne by Ontario ratepayers by a cumulative $42.6 million over the four-year period 2018-2021. In this scenario, Power Advisory estimated that a $6.54/MWh ETS rate would have increased ETS revenues by $245 million, but that the additional revenues would have been more than offset by the combination of $169 million less in congestion rents, $40.9 million less in export revenues, $18 million more in wind curtailment costs and $59 million more in waterpower curtailment costs.[57]

Power Advisory also estimated that "the financial benefit to Ontario ratepayers – i.e. costs they would avoid – would have been $33 million lower" if the ETS rate was reduced to $0/MWh (to zero)[58] over the four-year period and that if the increase to the ETS rate was half of what was modelled in its analysis, the net cost to Ontario ratepayers might be "to a large extent, half of what was included in [Power Advisory's] analysis."[59]

OEB staff accepts Power Advisory's contention that exports are price sensitive[60], even though the sensitivity is sometimes difficult to gauge precisely using publicly available information.[61] OEB staff also accepts the IESO's observation, which Power Advisory agreed with, that prices are a function of a complex interplay of supply, demand, behaviour-related and other factors within and outside of Ontario.[62]

While OEB staff commends Power Advisory's efforts to estimate the market impact of alternative ETS rates, OEB staff submits that the results of Power Advisory's analysis should be interpreted in general terms rather than literally. That is, OEB staff accepts that the ETS rate is one of a variety of factors and complex interactions at play in the electricity market. However, OEB staff is of the view that Power Advisory's point estimates of the net impacts to Ontario ratepayers of changes to the ETS rate may be exceeded by various uncertainties and approximations involved in the analysis and should be treated with open-minded caution.

This is compounded by the fact that the high and low ranges of Power Advisory's results[63] fall well below one-tenth of one percent of total electricity system costs paid by ratepayers[64] - a minimal margin. For additional perspective, Power Advisory's estimated $42.6 million cost to Ontario ratepayers from an increase in the ETS rate to $6.54/MWh is a cumulative value over a four-year period. The cumulative total cost of electricity

[57] *Ibid.*, pp. 42-43
[58] *Ibid.*, pp. 45-46
[59] EB-2021-0243, Power Advisory interrogatory response to OEB staff 5
[60] EB-2021-0243, Expert Report for the market impacts of changes to the ETS Rate, May 2022 (The Power Advisory Report), p. 35
[61] *Ibid.*, p. 35
[62] EB-2021-0243, Power Advisory interrogatory response to VECC 16; EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, p. 82; EB-2021-0243, Expert Report for the market impacts of changes to the ETS Rate, May 2022 (The Power Advisory Report), p. 5
[63] i.e., $42.6 million net cost under a $6.54/MWh ETS rate scenario, $33.7 million net benefit
[64] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, pp. 80-81

service in Ontario over a comparable four-year period would be over $84 billion (more than $21 billion per year).[65]

Power Advisory described the significant data limitations that it faced during its analysis and the approximating assumptions that it had to make in response. For example, Power Advisory identified data limitations with respect to things like wind curtailments[66], waterpower curtailments[67], historical PD-1 pricing for interties[68], information on export "sinks"[69], the value of Transmission Rights[70] and price quantity pairs.[71] While OEB staff appreciates that "Power Advisory had to reach conclusions with the best available information"[72], it also acknowledges Power Advisory's own assertion that certain sections of its report "highlight the severe lack of market data available and the inability to provide complete analysis to the [OEB] under this proceeding."[73]

OEB staff concurs with Power Advisory's opinion that "imports and exports are notoriously the trickiest thing to pin down." [74] According to Power Advisory, "you need multiple forecasts and you need multiple demand forecasts, and you need to try to figure out what the transaction cost is between the two is and where the sync is and where the source [sic], so they are inherently more complicated than other aspects of the grid."[75] OEB staff also notes that Power Advisory did not perform a sensitivity analysis on its results.[76] In OEB staff's view, this reduces the insight that can be drawn with respect to the sensitivity of key assumptions and on the robustness of Power Advisory's point estimates overall.

In summary, OEB staff agrees with Power Advisory that the electricity market implications it explored in its analysis are important considerations in relation to the ETS rate. OEB staff submits that while Power Advisory did an admirable job in its historic analysis despite data and other limitations, the results of its analysis should not be interpreted as a *fait accompli* in terms of specific electricity market implications of ETS rate changes, but as an open question to be considered.

Operability implications: OEB staff agrees with the IESO's statement that "interties with neighbouring jurisdictions provide a range of operational benefits and enhance system reliability for Ontario consumers."[77] OEB staff also accepts the IESO's assertion

[65] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, pp.76-80
[66] EB-2021-0243, Power Advisory interrogatory response to VECC 27
[67] EB-2021-0243, Power Advisory interrogatory response to VECC 23
[68] EB-2021-0243, Power Advisory interrogatory response to OEB staff 15
[69] EB-2021-0243, Power Advisory interrogatory response to SEC 4
[70] EB-2021-0243, Power Advisory interrogatory response to OEB staff 14
[71] EB-2021-0243, Expert Report for the market impacts of changes to the ETS Rate, May 2022 (The Power Advisory Report), p. 35
[72] EB-2021-0243, Power Advisory interrogatory response to OEB staff 15
[73] EB-2021-0243, Power Advisory interrogatory response to OEB staff 16
[74] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, p. 85
[75] Ibid.
[76] EB-2021-0243, Power Advisory interrogatory response to OEB staff 3
[77] EB-2021-0243, Submissions on the ETS Rate, Attachment 3, The IESO Report, p.15 (16 of 17)

that "in operational terms, interties provide flexibility that enable system operators to address power system needs and reliably manage the grid during changing system conditions."[78]

The IESO has stated that "an increase in the ETS rate will reduce exports and increase the risk that during periods of excess generation, over and above domestic needs, the IESO will need to take expensive and undesirable control actions to maintain reliability."[79] OEB staff suggests that the IESO has not substantiated that a higher ETS rate will reduce exports. In fact, the IESO also has stated elsewhere that "the ICP and ETS have an offsetting relationship such that an increase in the ETS will lead to a proportionate decrease in the ICP."[80]

That said, even without accepting the IESO's assertion that a higher ETS rate will necessarily lead to lower exports, OEB staff is sympathetic to the IESO's broader point that a decrease in exports (however it might come about) could, in some circumstances, lead to the need to curtail more Ontario supply than would otherwise be the case, and that doing so would not be economically optimal. In addition, OEB staff is sympathetic to the notion that beyond some level of renewable curtailment, there is some risk that the shutdown of some of Ontario's nuclear generation might have to follow. As such, OEB staff accepts the IESO's general point that curtailments have both economic and reliability dimensions (and that they should be avoided where possible).[81]

OEB staff submits that while exports support power system operability and economic efficiency, neither the IESO or Power Advisory has proven that an increase to the ETS rate will result in a greater need to curtail or shut down Ontario generation for reliability management purposes. The fact that the ETS and the ICP having an offsetting relationship, in the IESO's own estimation, adds to the uncertainty around how much of an impact a change to the ETS rate might have on export volumes.

While there is an uncertainty around the fine points of the relationship between the ETS rate and export volumes, considering the various factors and interactions involved in electricity market pricing and trade, OEB staff is nonetheless of the view that a measured approach to increasing the ETS rate is called for. That is, OEB staff submits that the precautionary principle ought to be considered when implementing changes to the ETS rate given the uncertainties and risks at hand. The precautionary principle here refers to the notion of "better be safe than sorry" amidst a lack of categorical proof of some potential future harm. In the context of a change to the ETS rate, the potential harm could be an increased likelihood, frequency, and cost of renewable curtailments and, down the line, of nuclear shutdowns. In brief, OEB staff submits that power system operability is an important issue that warrants ongoing consideration and recognition

[78] *Ibid*.
[79] EB-2021-0243, Presentation Day Materials, KP1.4: IESO Presentation, p. 5
[80] *Ibid*., p. 3 (4 of 17)
[81] EB-2021-0243, Technical Conference Transcript Day 1, July 28, 2022, pp. 180-184

throughout the implementation of a higher ETS rate.

Other uncertainties: The previous paragraphs have touched upon some electricity market and operability-related implications and uncertainties related to the ETS rate. OEB staff notes that other uncertainties exist which may have some relevance to the market and operations effects of changes to the ETS rate.

These include behavioural changes among exporters and other market participants following the implementation of the Market Renewal Program in the coming years, and an evolving supply mix in Ontario and surrounding jurisdictions and its implications on surplus generation, price spreads and congestion rents. The pace of the adoption of technologies that support surplus baseload management and power system operations - such as electricity storage - is another uncertainty.

The potential for a new interconnection between Ontario and its neighbours is another factor that could have an impact on electricity trade between Ontario and its trading partners. OEB staff notes that until the project was put on hold in early August 2022 due to external macroeconomic conditions, the Ontario Ministry of Energy had asked the IESO to enter into contract negotiations with ITC on the Lake Erie Connector project which would have established a new 1,000 MW high voltage bi-directional underwater transmission intertie between Ontario and Pennsylvania.[82,83]

OEB staff agrees with Power Advisory's opinion that a new intertie of this size could affect import and export dynamics.[84] OEB staff appreciates that such a new intertie was not factored into Power Advisory's analysis because the analysis focused on historical information rather than on the future. Notwithstanding, Power Advisory provides valuable perspective on the future in the following excerpt, which states that with or without the Lake Erie Connector project, Ontario faces a host of important uncertainties in the years ahead:

> "Ontario is facing a future that is very uncertain. The IESO is procuring thousands of megawatts. It hasn't done that for a long time. We don't know what those megawatts are, we don't know what the marginal cost is, we don't know how they're going to be committed. So the future, even with or without [the new 1,000 MW high voltage bi-directional underwater transmission intertie between Ontario and Pennsylvania] is probably more of a question mark we have seen for quite a while in the province. So I think the future is more uncertain than it was let's say three or four years ago."[85]

In OEB staff's view, the discussion and excerpt above underscores some of the factors

[82] EB-2021-0243, Exhibit I/Tab 6/ Schedule 7, Mr. Naren Pattani Interrogatory 7 referencing the IESO's December 2021 Planning Outlook
[83] EB-2021-0243, Exhibit JT-1.10
[84] EB-2021-0243, Technical Conference Transcript Day 2, July 29, 2022, pp. 95-96
[85] *Ibid.*, p. 96

that are likely to influence electricity trade patterns between Ontario and other jurisdictions in the future. OEB staff submits that these factors ought to be considered when setting and implementing changes to the ETS rate. The influence of these factors may well exceed the minimal margin that Power Advisory has estimated – on a historical basis, let alone on a predictive one - as being the net impact to Ontario ratepayers of either increasing the ETS rate or eliminating it altogether.

Rate impact to export class: OEB staff submits that the magnitude and pace of an increase to the ETS rate should also be considered in relation to the export class. An increase from the current ETS rate of $1.85/MWh to $5.42/MWh (the Curtailment Model ETS rate) would represent a significant change. The increase by $3.57/MWh from $1.85/MWh to $5.42/MWh would effectively represent a tripling of the current rate or an increase of 193%. This would follow a comparatively stable period of 22 years or more (i.e., 2000 to 2022+) during which the ETS rate has remained between $1/MWh and $2/MWh and has not been adjusted for inflation.[86]

OEB staff notes that the OEB's *Handbook to Utility Rate Applications* (Handbook) states that the OEB expects utilities to mitigate bill impacts through the pacing and prioritizing of investments and activities.[87] For electricity distributors, the Handbook states that the OEB has a policy requiring the filing of a mitigation plan when the total bill impact is 10% or more for any customer class. The Handbook also states that the "OEB expects all other utilities to propose mitigation plans, or explain why a plan is not required, when their proposals result in material impacts to customers."[88]

OEB staff submits that mitigation for the export class should be considered when setting and implementing a significant increase to the ETS rate.

Phase in of ETS rate increase: OEB staff recommends phasing in an increase to the ETS rate over a sufficiently long period of time. OEB staff recommends a phased-in approach to help mitigate the impact of the ETS rate increase on exporters; to recognize, in the spirit of precaution, uncertainties around the potential electricity market and operability implications of an increase to the ETS rate; and to allow opportunity for learning and, if necessary, adaptation.

OEB staff recommends gradually increasing the ETS rate with the longer-term aim of reaching a cost-based rate of $5.42/MWh, which corresponds to the Curtailment Model scenario result noted above. Along the way, OEB staff recommends pausing any increases to the ETS rate at an assessment point of $3.66/MWh, which corresponds to the "Hybrid Model" scenario result described by Elenchus in this proceeding. The assessment point would provide a predictable opportunity to review the performance of the ETS rate in light of the potential market and operability implications and behavioural

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[86] EB-2021-0243, Submissions on the ETS Rate, pp. 2 – 6. The ETS rate was set at $1/MWh between 2000 and 2010 and $2/MWh between 2011 and 2014; it has been set at $1.85/MWh since 2015
[87] OEB Handbook to Utility Rate Applications, October 13, 2016. Appendix 3, p. v
[88] *Ibid*.

and technological uncertainties noted above, and to address any other relevant considerations, including whether the OEB should continue to increase the ETS rate to $5.42. Considerations for OEB review in 2029 could also include updating the ETS rate to reflect the transmission rate base at the time. The recommended $5.42/MWh ETS rate is based on Hydro One's proposed 2023 revenue requirement.[89]

OEB staff recommends retaining the current $1.85/MWh ETS rate for all of 2023 as a way of providing lead-time to affected parties. OEB staff suggests increasing the ETS rate to $2.15/MWh starting in 2024, and then continuing to increase it linearly each year thereafter by approximately $0.30/MWh until it reaches $3.66/MWh in 2029.

OEB staff recommends a review of ETS rate performance in 2029, after the $3.66/MWh assessment point has been reached. The review would fall after Hydro One's rate term underpinning its application currently before the OEB (2023-2027)[90] and during its subsequent rate term, assuming that the next one will be for the period 2028 through 2032.

A pre-scheduled assessment point and review seven years in the future should provide enough time to organize a monitoring and analysis program in the meantime (as is discussed further in the next section). Results of the monitoring and analysis program can be considered during the assessment point review and next steps can be determined at that time.

Scheduling the assessment point and subsequent review between Hydro One cost-based rate applications may also facilitate parties' focus on the matter and might help make the workload more manageable for affected parties who might otherwise face competing demands on their time, attention, and effort.

According to OEB staff's phase-in suggestion, and as shown in Table 2, the ETS rate would remain at $1.85/MWh in 2023, reach the assessment point of $3.66/MWh in 2029, undergo a review in 2029, and then, if the OEB were to consider it appropriate to continue with the phased-in increase, reach $5.42/MWh by about 2035. The annual increase between 2024 and 2035 would be approximately $0.30/MWh. The cumulative increase of between 2023 and 2029 assessment point would be $1.81/MWh; the cumulative increase between 2023 and 2035 would be $3.57/MWh.

OEB staff notes that the annual increase of approximately $0.30/MWh proposed by OEB staff is well below the $1/MWh ETS rate increase approved by the OEB for 2012 (when the ETS rate was increased from $1/MWh in 2011 to $2/MWh in 2012). The increase is also much slower than the phase-in implemented by the OEB for pole attachments, in which the province-wide wireline pole attachment charge was increased

[89] EB-2021-0243, Submissions on the ETS Rate, Attachment 1: Export Transmission Service Rate Cost Allocation Methodology (The 2021 Elenchus Report), p. 31 (35 of 44)
[90] EB-2021-0110

from $22.35 to $43.63 in less than one year.[91]

Table 2: Notional long-term phase-in of a cost-based increase to the ETS rate between 2023 and 2035, with a holding point and review in 2029

Year	ETS Rate ($/MWh)
2023	1.85
2024	2.15
2025	2.45
2026	2.75
2027	3.05
2028	3.35
2029	**3.66**
2030	3.95
2031	4.25
2032	4.55
2033	4.85
2034	5.15
2035	**5.42**

OEB staff acknowledges that its proposed approach does not account for the effects of inflation (or any other changes in underlying costs), as the proposed rate trajectory is underpinned by a single year's cost projection (for 2023). This is done with intent, with rate mitigation in mind. The approach proposed above by OEB staff includes several forms of rate impact mitigation. The first is a one-year lead time for implementing an ETS rate increase, starting in 2024. Second, the proposed ETS rate target reflects Hydro One's applied-for 2023 transmission revenue requirement: OEB staff does not propose to update the ETS rate to incorporate any evidentiary updates associated with inflation put forth by Hydro One in its current transmission cost of service proceeding[92], nor does it propose any annual updates associated with inflation at this time. Third, the proposed ETS rate increase is phased in over a period of twelve years, between 2024 and 2035.

OEB staff proposes a cost-based mid-term review of the ETS rate in 2029 to address matters that the OEB deems relevant, including any inflationary pressures associated with the rate, and whether the OEB should continue to increase the ETS rate to $5.42.

Monitoring and analysis: OEB staff recommends that an electricity export monitoring and analysis program should be established to support future reviews of the ETS rate. The monitoring and analysis program should include the consideration of factors that are relevant to understanding the performance of Ontario's export markets and the

[91] *Ibid.*, p. 4 (5 of 56)
[92] EB-2021-0110

performance of the ETS rate in relation to electricity markets and reliability. OEB staff notes Power Advisory's statements in this proceeding on the absence of certain market information in the public realm that would have facilitated a review of Ontario's electricity export markets and provided additional information on the implications of potential changes to the ETS rate.

OEB staff recommends that the program should be overseen and conducted by an independent party, such as the IESO. The OEB may wish to consider inviting the IESO to work with others to establish the scope of an electricity export monitoring and analysis program; to conduct the monitoring and analysis on an ongoing basis, either on its own or through a third party or parties; to report on its findings at some regular frequency; and to support the OEB's future reviews of Ontario's ETS rate.

However the work program is organized and administered, OEB staff recommends that the monitoring and analysis activities should commence within the next few years to allow for the development of results that could be considered the next time the ETS rate is reviewed, such as during the review recommended by OEB staff in 2029.

Review frequency and timing: OEB staff recommends that a cost-based ETS rate should be subject to annual inflation adjustments after it reaches a steady-state at the recommended $5.42/MWh, or sooner if the OEB so decides. Hydro One has provided a helpful illustration of how an annual inflation adjustment to the ETS rate might work.[93] Specifically, Hydro One suggested in its illustration that a "mechanistic way of adjusting the ETS during the rate-setting term would be to adjust the year's OEB-approved ETS rate by the same [revenue cap index] amount that is used to adjust Hydro One's transmission revenue requirement". OEB staff takes no issue with this approach.

Aside from inflation adjustments, OEB staff recommends that the ETS should be reviewed in greater detail from time to time, but not too frequently (given the relatively small scale of ETS revenues compared to Ontario's electricity costs).

OEB staff suggests that a review of the ETS rate once every ten years would be adequate, starting in 2029 once the ETS rate has reached the assessment point of $3.66/MWh proposed by OEB staff, and then again in 2039, followed by further review once every ten years.

That said, given that this is the first full cost based review of the ETS rate, OEB staff recommends an assessment point in 2029 as discussed earlier, at which time the OEB could consider a number of options including the appropriateness of continuing with the phased-in increase reaching $5.42/MWh by 2035, a re-examination of the costs, a framework for any inflationary adjustments going forward, any interim reviews and/or to confirm the ten year rate plan.

OEB staff recognizes that the OEB may wish to call for a detailed review at any point in

[93] EB-2021-0243, Exhibit JT-1.2, August 4, 2022 (Hydro One Undertaking JT-1.2)

time as it sees fit. Ongoing reporting from the monitoring and analysis program discussed above might assist the OEB in determining whether an interim review of the ETS rate is required at any time.

Administration:

OEB staff supports Hydro One's suggestion that, with respect to settlement, ETS revenue should continue to be remitted to Hydro One.[94] OEB staff agrees with Hydro One's view that "from a customer and rate perspective the outcome is the same since any ETS revenues that would flow to other transmitters would have to be deducted from their approved revenue requirement for the purpose of calculating UTR rates." OEB staff agrees with Hydro One that maintaining the existing ETS settlement methodology will continue to allow for full recovery of transmitter revenue requirements through the UTR in an administratively simple way.[95]

~All of which is respectfully submitted~

[94] EB-2021-0243, Exhibit I/Tab 1/Schedule 4, Interrogatory response to OEB staff 4(a)
[95] Ibid.