PUBLIC INTEREST ADVOCACY CENTRE
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June 17, 2022 **VIA E-MAIL**

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Toronto, ON

Dear Ms. Marconi:

Re: Generic UTR Issues Proceeding
Export Transmission Service Rate
VECC Interrogatories
Ontario Energy Board File Number: EB-2021-0243

Please find attached the VECC's interrogatories for Power Advisory in the above-noted proceeding. This document has been sent to all registered parties to this proceeding.

Yours truly,

William Harper
Consultant for VECC/PIAC

Email copy:
All parties to EB-2021-0243

REQUESTOR NAME:	**VECC**
INFORMATION REQUEST ROUND NO:	**#1**
TO:	**POWER ADVISORY LLC**
DATE:	**June 17, 2022**
PROJECT NO:	**EB-2021-0243**
APPLICATION NAME:	**Generic Uniform Transmission Rates – Export Transmission Service Rate**

1.0 Reference: Power Advisory Evidence, pages 4; 7-8 and 16-18

Preamble: At page 4 the Evidence quotes the OEB's Decision on Expert Evidence and Procedural Order No. 2 as follows: "APPrO has stated that Mr. Lusney and Mr. Yauch have considerable expertise in energy market analysis, regulatory affairs, generation development, system planning, market assessment and energy policy analysis. The OEB is prepared to accept both Mr. Lusney and Mr. Yauch as experts in energy market and energy policy analysis for this evidence, and will proceed on that basis. It is not clear whether Mr. Lusney or Mr. Yauch are experts in regulatory affairs, but the OEB concludes this is not required for this evidence. Previous appearances before a regulatory tribunal provide helpful experience in regulatory affairs, but do not necessarily qualify a person as an expert in the field."

At pages 7-8 the Evidence provides an overview regarding the areas of experience and expertise of the two authors.

At pages 16-18 the Evidence provides commentary and critique regarding the cost allocation methodology proposed by Elenchus.

1.1 It is noted that neither Mr. Lusney nor Mr.Yauch has been accepted by the OEB as an expert in the area of cost allocation (and more specifically cost allocation as it relates to transmission tariffs). Is the commentary and critique of Elenchus' proposed cost allocation methodology meant to represent an "expert opinion"?

1.2 If yes, is the OEB now being requested to accept Mr. Lusney and Mr. Yauch as experts in cost allocation and, if so, on what basis?

2.0 Reference: Power Advisory Evidence, pages 5 and 34-46
Exhibit I, Tab 8, Schedule 7 a), IESO's 2021 APO

Preamble: At page 5 the Evidence states:
"Given the highly complex nature of the electricity market – both in Ontario and other jurisdictions – the report is as simplified as is reasonably possible. Electricity trading is highly dynamic, involves many physical and financial considerations and occurs amidst the real-time balancing of an incredibly complex physical electricity grid. This report captures that complexity to the greatest extent possible and provides an analysis on how traders and other market participants would respond to a change in the ETS rate – which, if increased, would materially change the transactional cost of energy trading from Ontario into neighbouring markets. <u>Where possible, we have focused on simplicity rather than attempt to capture the many nuances – both physical and financial – that are evident in Ontario's electricity sector. We have also undertaken a historical analysis to avoid complications around forecasting future conditions</u>". (emphasis added)

2.1 Given the above comments, should readers of the Evidence interpret the results presented on pages 34-46 as an indication regarding the "directional impacts" of higher or lower ETS rates as opposed to specific estimates as to the impact of increasing or decreasing ETS rates by the amounts assumed in the Evidence over the historical period used in the analysis?

2.1.1 If not, why not?

2.2 Given that the analysis was performed using data from the historical period 2018-2021, to what extent does the applicability of the results to the period 2023-2027 (i.e., the period covered by Hydro One's current Joint Transmission and Distribution Rate Application) depend on electricity market conditions in Ontario for the period 2023-2027 being similar to those in 2018-2021?

2.2.1 If the applicability does not depend on the market conditions being similar please explain why.

2.2.2 If the applicability does depend on the market conditions being similar, what are the market conditions for which similarity is particularly important for the results to be applicable and why? Also, based on the IESO's 2021 APO, are these conditions expected to similar over the 2023-2027 period?

3.0 Reference: Power Advisory Evidence, page 9

Preamble: The Evidence states:

"Hydro One's joint transmission and distribution application proposes increasing in the ETS rate from its current level of $1.85/MWh to $6.54/MWh (on an adjusted basis). An increase of this magnitude will impose additional costs on Ontario ratepayers, resulting in higher electricity-related charges for domestic ratepayers, while reducing the economic efficiency of the grid. The ETS rate acts as a transactional cost to export traders when engaging in energy trading. 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. The net impact on Ontario's ratepayers is negative."

3.1 Please indicate where in its EB-2021-0110 Application Hydro One proposes that the ETS rate be increased to $6.54 (on an adjusted basis).

3.2 With respect to the first reference above, please explain what is meant by "all else being equal".

3.3 With respect to the first reference above, please confirm that based on the analysis presented in the Evidence (pages 38-39) increasing the ETS rate also increases overall ETS revenues which benefits Ontario ratepayers.

3.4 With respect to the first reference, does increasing the ETS result: i) in less supply being exported, ii) reduced congestion rents <u>and</u> iii) increased curtailment of baseload generation in all hours of the year?

3.4.1 If not, under what circumstances will each "result" occur?

3.4.2 If not, how many hours in each of the years 2018-2021 were the circumstances such that each of the claimed results would have occurred?

3.4.3 If yes, please explain why.

4.0 Reference: Power Advisory Evidence, page 9
Exhibit I, Tab 5, Schedule 15.2

Preamble: The Evidence states (page 9):
"A higher transaction cost will, in general, reduce exports in hours when it is economically advantageous to sell Ontario supply into neighbouring markets (i.e. when prices are lower in Ontario)".

The Evidence states (page 10);
"Increasing the ETS rate – which acts as a transactional cost – reduces the overall efficiency of energy trading and the province's electricity sector as a whole."
And
"Given that energy exports are a net benefit for Ontario ratepayers and do not impose any costs on Ontario ratepayers, the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading."

4.1 What is meant by "when prices are lower in Ontario" (page 9)? Is this referring to hours when the Ontario HOEP is less that the price of electricity in the neighbouring market?

4.2 What does Power Advisory mean by the terms "the overall efficiency of energy trading" and "economic efficiency of energy trading"?

4.3 Please explain what Power Advisory means by "transactional costs".

4.4 Does Power Advisory consider congestion payments (based on ICP) and/or Uplift charges to be transactional costs?

4.4.1 If not, why not given they are also part of the cost of an export transaction?

4.4.2 If yes, does Power Advisory consider congestion payments to be inhibiting "economically advantageous sales from Ontario to neighbouring markets" and reducing "the overall efficiency of energy trading"?

4.4.3 If yes, does Power Advisory consider the levying of uplift charges to be inhibiting "economically advantageous sales from Ontario to neighbouring markets" and reducing "the overall efficiency of energy trading"? In responding please address the fact that a portion of the uplift charges does not vary with the level of exports. (per Exhibit I, Tab 5, Schedule 15.2).

5.0 Reference: Power Advisory Evidence, pages 10 and 46-48

Preamble: The Evidence states (page 10):
"Given that energy exports are a net benefit for Ontario ratepayers and do not impose any costs on Ontario ratepayers, the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading."

In its final conclusions regarding a higher or lower ETS rate Power Advisory notes the impact of a higher or lower rate but does not make any specific recommendation regarding the appropriate level for the ETS rate.

5.1 By stating that "the ETS rate should continue to be set at a low level to further enable the economic efficiency of energy trading" is Power Advisory recommending that the ETS rate be maintained at its current level of $1.85/MWh?

5.2 If not, does Power Advisory have a recommendation as to the appropriate level for the ETS rates and, if so, what is it?

6.0 Reference: Power Advisory Evidence, page 10 (Table 1)

6.1 Please confirm that the heading for the second column should read "Increasing ETS Rate to $6.54/MWh" and not "$4.69/MWh".

7.0 Reference: Power Advisory Evidence, page 12

Preamble: The Evidence states:
"Ultimately, a settlement agreement was reached between Hydro One and parties to the proceeding that included an ETS rate of $1.85/MWh (a simple average compromise between the $2/MWh rate in place and the $1.70 proposed by Elenchus)[6]". Footnote #6 states "See the Draft Rate Order for EB-2014-0357).
And
"The important takeaway from the history of the ETS rate is that determining the most "efficient" level has been subject to competing claims for nearly two decades and has never been set on an "economically efficient" basis."

7.1 With respect to the first reference, please indicate where in the Draft Rate Order for EB-2014-0357 it states the $1.85 was based on "a simple average compromise between the $2/MWh rate in place and the $1.70 proposed by Elenchus".

7.2 Please confirm that the Settlement Agreement filed in EB-2014-0140 and which established the $1.85 did not indicate that the

$1.85 was arrived at as a result of simply averaging the $2/MWh rate in place and the $1.70 proposed by Elenchus.

7.3 With respect to the second reference, is it Power Advisory's view that setting the ETS rate should be based solely on considerations of economic efficiency (i.e., what is the most (economically) efficient level for the rate)?

7.3.1 If not, what other considerations should be taken into account when setting the ETS rate?

7.3.2 If not, how has Power Advisory taken these other considerations into account in drawing its conclusions and making its recommendations regarding the appropriate level for the ETS rate?

8.0 Reference: Power Advisory Evidence, page 15

Preamble: The Evidence states:
"When a greater number of trades are uneconomic, overall energy trading is reduced and the value of moving Ontario's energy supply to neighbouring jurisdictions decreases."

8.1 Apart from additional revenues from ETS rates, Uplift charges and congestion charges (i.e., ICP) and the avoided curtailment of baseload generation, does moving Ontario's energy supply to neighboring jurisdictions provide "value" to Ontario consumers/ratepayers?

8.1.1 If yes, please explain what the additional sources of "value" are and under what market/system conditions it will accrue to Ontario ratepayers?

9.0 Reference: Power Advisory Evidence, page 15
Exhibit I, Tab 1, Schedule 29
Exhibit I, Tab 6, Schedule 3 and Schedule 4
Hydro One's ETS Submissions, Attachment 3, page 14

Preamble: The Power Advisor Evidence states:
"The IESO evidence repeatedly notes the different market design of export pricing at the province's interties compared to other jurisdictions, which were discussed in both the Elenchus and CRA evidence. Ontario's dynamic design for determining congestion rents is not replicated in other markets and – given how material congestion rents have been in recent years – understates the true cost (and value to Ontario ratepayers) of exporting energy from Ontario into neighbouring jurisdictions."

CRA's response in Exhibit I, Tab 1, Schedule 29 states:

"In its review of ETS rates for 2020, CRA did not find any evidence that specific market based outcomes were considered in the setting of ETS rates".

CRA's response in Exhibit I, Tab 6, Schedule 4 states: "CRA confirms that in American jurisdictions covered by the CRA Report, Exports as well as loads pay for energy on the basis of Locational Marginal Pricing (LMP) which also includes cost of congestion and losses."

In its initial submission (Attachment 3) the IESO states: "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."

9.1 While Ontario's market design approach to determining congestion rent is not replicated in the other markets, does Power Advisory agree with CRA's comment (Exhibit I, Tab 6, Schedule 4) that for other markets the use of LMP means the costs of exports in these other markets also includes congestion rent/pricing?

9.1.1 If not, why not?

9.2 In these markets will the level of the ETS rate charged for exports impact the LMP at its interties?

9.2.1 If not, why not?

9.3 Does Power Advisory agree with CRA's response (Exhibit I, Tab 1, Schedule 29) that in the jurisdictions neighbouring Ontario specific market outcomes are not considered in the setting of ETS rates?

9.3.1 If not, please identify the jurisdictions where specific market outcomes are not considered in the setting of ETS rates and describe how this is done.

10.0 Reference: Power Advisory Evidence, pages 14, 16-18 and 54

10.1 What does Power Advisory understand to be the purpose of a cost allocation study?

10.2 In Power Advisory's view is there difference between "cost allocation" and "rate design" when it comes to the setting of: i) rates in general and ii) ETS rates in particular?

10.3 At page 54, under Professional Experience, Mr. Lusney's CV includes the following: "Represented through expert evidence and testimony the Utility Consumer Advocate Alberta during Transmission Rate Tariff hearing in front of the Alberta Utility Commission as an expert witness on transmission planning and cost allocation". Please provide the following: i) a copy of Mr. Lusney's evidence in the noted proceeding and ii) an internet link to where a record of proceeding and the AUC's decision can be found. Note: If there is no "link", please also provide a copy of the AUC's final decision.

10.4 With respect to Figure 1 (page 18), please confirm that the figure indicates the number of hours where the clearing price was at or below \$0/MWh (as indicated in the title) and not the number of hours the clearing price was below \$0/MWh (as indicated in the vertical axis' label).

10.5 With respect to Figure 1 (page 18), please provide a similar figure based on the number of hours the clearing price was at or below \$5/MWh.

10.6 With respect to Figure 1 (page 18), please provide a breakdown as to the number of hours the clearing price was at or below \$0/MWh for each of the years 2018, 2019, 2020 and 2021 for Ontario.

10.7 During the 2018-2021 period, did surplus baseload generation conditions exist in all of the hours when the clearing price was at or below \$0/MWh in Ontario (per Figure 1)?

10.7.1 If not, what other market conditions led to the clearing price being at or below \$0/MWh?

10.8 During the 2018-2021 period, was the Ontario clearing price at or below \$0/MWh in Ontario in all hours when surplus baseload generation conditions existed in Ontario?

10.8.1 If not, why not?

10.9 During the 2018-2021 period, did surplus baseload generation conditions exist in all of the hours when the market clearing price was at or below \$5/MWh?

10.9.1 If not, what other market conditions led to the clearing price being at or below $5/MWh?

10.10 During the 2018-2021 period was the Ontario clearing price at or below $5/MWh in all hours when surplus baseload generation conditions existed in Ontario?

10.10.1 If not, why not?

11.0 Reference: Power Advisory Evidence, pages 21-22

Preamble: The Evidence states:
"When HOEP is $0/MWh or below, hydro supply remains, on average, around 3,000 MW – meaning it is offering a significant amount of supply at a price well below its marginal cost, which includes the Gross Revenue Charge (GRC), among other costs. In these hours, hydro generators are selling energy at a "loss" based on market prices. Selling supply at a "loss" reduces the economic efficiency of the wholesale market, but occurs often in Ontario as a combination of the hybrid design and surplus baseload supply".

11.1 Please explain how Figure 4 was created. As part of the response please provide a figure (i.e., a scatter diagram) that plots the hourly HOEP values against the MW of hydro supply used in the creation of Figure 1.

11.1.1 Based on this data is the increase in the MW of hydro supply as HOEP increases statistically significant?

11.2 What was the marginal cost of hydro supply over the period 2018-2021?

11.3 With respect to Figure 4, do the MW of hydro supply increase if the HOEP increases to levels higher than $15/MWh?

11.3.1 Does the level of hydro supply increase when HOEP rises to levels above the marginal cost of hydro supply? If yes, why?

11.4 Why does selling supply at a loss reduce economic efficiency, when the price is being set by the market?

12.0 Reference: Power Advisory Evidence, page 22

Preamble: The Evidence states:

"A significant amount of generating capacity in Ontario falls under OEB rate regulation – including OPG's nuclear assets at both the Darlington Nuclear Generating Station ("Darlington") and the Pickering Nuclear Generating Station ("Pickering"), as well as the heritage hydroelectric assets described previously. Nearly all other capacity in Ontario is signed to long-term contracts with the IESO, including the Bruce Nuclear Generating Station ("Bruce"), wind and solar generators and gas-fired generators. Both contracted and regulated assets are typically made financially whole for supply sold in the wholesale market. For example, output from a wind contract may be contracted with the IESO at $135/MWh – meaning it will be paid that amount for any MW it sells into the wholesale market. If HOEP is $10/MWh, it will receive a $125/MWh payment, which is recovered from ratepayers through the Global Adjustment".

12.1 For baseload supply (i.e., nuclear, must-run hydro and wind and solar) is the total compensation received the same under each of the following conditions: i) the generator chooses not to bid into the Ontario market, ii) the generator bids and the bid clears for sale into the Ontario market, iii) the generator bids and the bid does not clear for sale into the Ontario market, and iv) the generator bids, the bid clears for sale into the Ontario market but the generator is directed by the IESO to curtail (or maneuver) it generation?

12.1.1 If not, what are the differences and why? In the response, please distinguish by source of generation if required.

12.2 For baseload supply (i.e., nuclear, must-run hydro and wind and solar) is the net compensation received (i.e., total compensation less marginal costs) the same under each of the following conditions: i) the generator chooses not to bid into the Ontario market, ii) the generator bids and the bid clears for sale into the Ontario market, iii) the generator bids and the bid does not clear for sale into the Ontario market, and iv) the generator bids, the bid clears for sale into the Ontario market but the generator is directed by the IESO to curtail (or maneuver) it generation?

12.3 If not, what are the differences and why? In the response, please distinguish by source of generation if required.

13.0 Reference: Power Advisory Evidence, page 23

Preamble: The Evidence states:
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."
And
"The key point is that Ontario has a significant amount of baseload supply that will – in many hours – push HOEP below both the marginal cost of market participants, but also significantly below contracted or regulated rates."

13.1 Does the presence of a significant amount of baseload supply result in HOEP being below the marginal cost of all market participants or just some market participants for many hours of the year?

13.1.1 If all, please explain why.

13.2 Over the 2018-2021 period, what was the total amount of SBG annually and, in each year, how much of this was resolved through exports and how much was through managing (via nuclear maneuvering, wind and solar curtailment, etc.) supply?

13.3 Is SBG only resolved through curtailment, spill or maneuvering (i.e., the second of the two mechanisms discussed in the first reference) when exports ties are constrained and no more supply can be exported?

13.3.1 If not, please explain why.

13.4 What is Power Advisory's understanding as to the total amount of SBG that the IESO expects will occur annually over the 2023-2027 period that will need to be resolved through either exports or "managing" supply?

14.0 Reference: Power Advisory Evidence, pages 24-26

14.1 What point in time is the data set out in Figure 5 based on?

14.2 Do Figures 5 and 6 include all of Ontario's hydro supply or just thea "must-run" hydro supply?

14.3 With respect to the figure on page 26, what period (i.e., time-frame) are the values based on?

14.4 With respect to the figure on page 26, for each of the jurisdictions please provide a scatter diagram that for the period used plots the frequency at which different hourly prices occur using intervals of $1 (i.e. frequency of prices in the $1-$2 range, the $2-$3 range, etc.)

15.0 Reference: Power Advisory Evidence, pages 9 and 28-29

Preamble: The Evidence states (page 9):
"The ETS rate acts as a transactional cost to export traders when engaging in energy trading. 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".

15.1 With respect to Figure 8, if the ETS rate were to increase by $5/MWh would this lead to each of the bids shown in the Figure being $5 less?

15.1.1 If not, why not?

15.1.2 If yes, given such an event would the level of exports remain unchanged from that shown in Figure 8?

15.2 With respect to Figure 8, if the ETS rate were to decrease by $2/MWh would this lead to each of the bids shown in the Figure being $2 more?

15.2.1 If not, why not?

15.2.2 If yes, given such an event would the level of exports remain unchanged from that shown in Figure 8?

15.3 With respect to Figure 9, if the ETS rates were to increase by $5/MWh would this lead to each of the bids shown in the Figure being $5 less?

15.3.1 If not, why not?

15.3.2 If yes, given such an event would the level of exports remain unchanged but the ICP be reduced from $20/MWh to $15/MWh?

15.4 With respect to Figure 9, if the ETS rates were to decrease by $2/MWh would this lead to each of the bids shown in the Figure being $2 more?

15.4.1 If not, why not?

15.4.2 If yes, given such an event would the level of exports remain unchanged but the ICP be increased from $20/MWh to $22/MWh?

16.0 Reference: Power Advisory Evidence, pages 31-32

16.1 With respect to paragraph 77 and Figure 10, has Power Advisory undertaken any analysis to determine if there is a "statistically" significant trend/relationship between the level of exports to NYISO and the NYISO/HOEP price spread?

16.1.1 If yes, what were the results?

16.2 Has Power Advisory investigated the relationship between the level of exports to other interconnected jurisdictions and the price spread between the HOEP and the hourly price in those jurisdictions?

16.2.1 If yes, is the relationship similar to that for the HOEP-NYISO price spread versus exports?

17.0 Reference: Power Advisory Evidence, pages 5 and 35-37

17.1 Please explain how the "average export" line in Figure 13 was developed (e.g., were individual trend lines established for each of the $5 intervals?).

17.2 At page 5 the Evidence states that one of the issues that would be addressed was "a statistical analysis on the sensitivity of Ontario exports to price changes". Was the trend line shown in Figure 14 established using statistical analysis such as regression analysis?

17.2.1 If yes, what was the standard deviation associated with the relationship and is the trend statistically significant (i.e., is there a statistically significant relationship between changes in HOEP and the change in the level of exports)?

17.2.2 If not, please undertake a statistical analysis of the sensitivity of Ontario exports to change in the level of the HOEP based on the data set out in Figure 14 and report the results including the standard deviation associated with coefficient for HOEP.

17.3 At page 35 the Evidence states “Focusing on exports when prices are between $0/MWh and $50/MWh – which would incorporate the marginal cost of a majority of Ontario’s supply mix – a $5/MWh increase in the Ontario price results in 160 MW reduction in hourly export volumes”. Please provide a schedule setting out how the 160 MW was derived.

17.4 At pages 35-36 the Evidences states: “More importantly, looking at exports when the Ontario price moves from $0/MWh to $5/MWh – likely when Ontario is experiencing severe SBG and curtailment – hourly exports decrease, on average, by nearly 280 MW”. Please provide a schedule setting out how the 280 MW was derived.

17.5 At page 35 the Evidence states: “But we need to be clear: there are a number of limitations with available public data compared to what is required to provide a highly accurate estimate price elasticity and system-wide benefits of exports.” Given this qualification how accurate are the 160 MW and 280 MW estimates and what is the 50% confidence interval (based on the statistical analyses discussed above) that is associated with each?

18.0 Reference: Power Advisory Evidence, page 38

Preamble: The Evidence states: “Congestion prices on the interties are also inversely related to HOEP. As HOEP moves higher, congestion rents decrease and vice versa. Looking at congestion rent in hours when HOEP ranges from $0/MWh to $20/MWh – which, again, incorporates the marginal cost of Ontario’s baseload supply resources, including nuclear, hydro and wind/solar – a $5/MWh increase in the intertie price can reduce the congestion price by as much as $5/MWh on certain interties (notably on the Michigan intertie).”

18.1 Figure 15 is based on data from what period in time?

18.2 Are the values used to create Figure 15 based on all of the hours for this period, including those when there was no congestion rent?

18.2.1 If not, please re-do Figure 15 and include those hours.

18.3 For each of the five jurisdictions portrayed in Figure 15 please provide a scatter diagram (similar to Figure 14) that plots hourly values for congestion rent against the HOEP value in the same hour based on the data used to create Figure 15.

18.3.1 For each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $20/MWh range?

18.3.2 For each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $5/MWh range?

18.4 If Figure 15 did not include those hours when there was no congestion rent, then please provide a scatter diagram for each of the five jurisdictions that also includes those hours.

18.4.1 Based on this data, for each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant when all values for HOEP in the $0/MWh to $20/MWh range are considered?

18.4.2 Based on this data, for each of the five jurisdictions, is the relationship between HOEP and Congestion Rent ($/MWh) statistically significant considering all values for HOEP in the $0/MWh to $5/MWh range?

18.5 Based on the foregoing statistical analyses, what is the 50% confidence interval for the estimated $5 reduction in congestion rent due to a $5 increase in HOEP?

19.0 Reference: Power Advisory Evidence, pages 38-39
Hydro One's ETS Submissions, Attachment 3, page 12
Exhibit I, Tab 6, Schedule 6 a)

Preamble: In Attachment 3 the IESO states:
"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".

The response in Exhibit I, Tab 6, Schedule 6 a) states: "ICP is only applicable during times of congestion."

19.1 Please provide a schedule setting out how the 17 TWh reduction in exports sales based on a $4.69/MWh increase in the ETS rate was calculated (per paragraph 93). As part of the response please provide the source/basis for all inputs used.

19.2 How does Power Advisory's calculation of the decrease in export volumes due to an increase in the ETS rates account for the fact (per the IESO submissions, page 12) that an increase in the ETS rate will not impact export flows in hours when the ICP is greater than the ETS rate increase?

19.3 Please provide a schedule setting out how the $169.0 million reduction in congestion revenue based on a $4.69/MWh increase in the ETS rate was calculated. As part of the response please provide the source/basis for all inputs used.

19.4 How does Power Advisory's calculation of the decrease in congestion rents due to an increase in the ETS rates account for the fact (per the IESO response to Exhibit I, Tab 6, Schedule 6) that ICP is only applicable during times of congestion?

20.0 Reference: Power Advisory Evidence, pages 39-41

Preamble: The Evidence states (page 40):
"Nearly all wind assets are signed to long-term, contract-for-difference (CfD) contracts with the IESO. A CfD contract pays a wind asset owned a fixed rate for every MWh of supply. Many of the CfD rates are set at $135/MWh or greater (due to inflation clauses in the contract)".
And
"Given the lack of hourly curtailment amounts, Power Advisory estimates wind curtailment by comparing forecasted versus actual output in hours when HOEP is below $5/MWh."

The Evidence states (page 41):
"Using the previous methodology to calculate curtailment payments, average annual wind curtailment costs Ontario ratepayers around $200 million annually (recognizing this is a high-level estimate).

20.1 Please provide a schedule that sets out Power Advisory's calculation of $200 million as being the annual cost of wind curtailment.

20.2 Is $135/MWh used by Power Advisory in determining the $200 million estimate for the annual cost of curtailing wind (paragraph 100)?

20.2.1 If yes, please indicate the source of this value and provide supporting references that indicate most wind contracts are based on CfD rates using this (or a higher) value.

20.2.2 If not, what $/MWh cost for wind curtailment was used and what was it based on?

20.3 Please explain why comparing forecasted versus actual output for wind is reasonable way to estimate curtailment. Could the change between forecast and actual wind output also be due to changes in weather and wind patterns as between forecast and actual?

20.4 Over what years was the average annual value of $200 million calculated?

20.4.1 If more than one year, please provide the estimated annual values for each year.

21.0 Reference: Power Advisory Evidence, page 41

Preamble: The Evidence states:
"A higher ETS will reduce exports in hours when the province is curtailing wind supply (and vice versa). Relying on Power Advisory's estimate of wind curtailment, a higher ETS will result in as much as 7.6 TWh of increased wind curtailment between 2018 and 2021. Given that curtailment only occurs (in our model) when HOEP is $5/MWh or below, the financial impact to Ontario ratepayers totals as much as -$17.9 million over that time frame".

21.1 Is the "higher" ETS rate referred to $6.54/MWh (an increase of $4.69/MWh)? If not, what is the higher rate?

21.2 Please provide a schedule setting out Power Advisory's calculation that the higher ETS rate will result in "as much as 7.6 TWh of increased wind curtailment between 2018 and 2021".). As part of the response please provide the source/basis for all inputs used.

21.2.1 Please explain what is meant by "as much as". Did the Power Advisory model provide a range for the estimated amount of increased wind curtailment and, if so, what was the "range"?

21.3 Please provide a schedule setting out Power Advisory's calculation of the $17.9 M increase in curtailment costs as result of the modelled increase in the ETS rate. As part of the response please provide the source/basis for all inputs used.

22.0 Reference: Power Advisory Evidence, pages 23, 33 (Figure 11), 38 (Figure 15) and 40-41
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble: The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams

can be “spilled”; and wind and solar turbines can be “curtailed.”

The Evidence states (page 41):
“A higher ETS will reduce exports in hours when the province is curtailing wind supply (and vice versa). Relying on Power Advisory’s estimate of wind curtailment, a higher ETS will result in as much as 7.6 TWh of increased wind curtailment between 2018 and 2021. Given that curtailment only occurs (in our model) when HOEP is $5/MWh or below, the financial impact to Ontario ratepayers totals as much as -$17.9 million over that time frame”.

In Attachment 3 the IESO states:
““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”.

Figure 15 in the Evidence indicates that when HOEP is at $5/MWh or less the congestion rent averages in excess of $15/MWH on the Michigan interties and in excess of $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario’s exports.

22.1 At a HOEP of $5/MWh or less will wind generation only be curtailed when the interties are congested and no more surplus baseload generation can be exported?

22.1.1 If not, under what other circumstances would wind generation need to be curtailed?

22.2 According to Power Advisory’s model wind curtailment occurs when HOEP is $5/MWh or less. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario’s two largest export markets) is greater than $5/MWh when HOEP is in this range. Furthermore, at this level of ICP the IESO’s evidence is that an increase in ETS rates of $5/MWh would reduce the ICP but have no impact on export flows. Does this mean that, in many instances, an increase in ETS rate of $5.00/MWh would not reduce exports during times of surplus wind generation and therefore would not lead to increased curtailment of wind generation?

22.2.1 If not, why not?

22.2.2 If yes, how has this been taken into account in Power Advisory's calculation that wind generation curtailment would increase by "as much as 7.6 TWh" between 2018 and 2021 if the ETS rate increased by $5/MWh?

23.0 Reference: Power Advisory Evidence, pages 41-42

Preamble: The Evidence states (page 41):
"A higher ETS will also impact exports of regulated hydro supply, which given the regulated rate of $43/MWh and the surplus baseload variance account that makes OPG financially whole for any spilled energy, will increase system-wide costs for Ontario ratepayers. Power Advisory's analysis focused on the impact to exports when HOEP moves from $15/MWh to $20/MWh – mimicking the increase a higher ETS will have on exports. The reason the analysis focuses on this range in the economic merit order is that this is the threshold where the marginal cost of OPG's large hydro assets either experience surplus supply (and will target exports) compared to being economically dispatched".

The Evidence states (page 42):
"Power Advisory's analysis assumes that the decrease in exports when HOEP increases from $15/MWh to $20/MWh – which is a proxy for an increase in the ETS rate of $5/MWh – results in a 4.1 TWh reduction in hydro exports over the 2018 – 2021 time frame and increase in spilled energy. The cost to Ontario ratepayers is $14.40 MWh for every unit of energy that is spilled and not exported."

23.1 Please provide a schedule that sets out Power Advisory's calculation of the 4.1 TWh reduction in hydro exports due to an increase in the ETS rate of $5/MWh. As part of the response please provide the source/basis for all inputs used.

23.2 Please provide a schedule setting out Power Advisory's calculation of the $14.40/MWh cost for every unit of hydro energy that is spilled. As part of the response please provide the source/basis for all inputs used.

24.0 Reference: Power Advisory Evidence, pages 23, 33 (Figure 11), 38 (Figure 15) and 41-42
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble: The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy

traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."

The Evidence states (page 42):
"Power Advisory's analysis assumes that the decrease in exports when HOEP increases from \$15/MWh to \$20/MWh – which is a proxy for an increase in the ETS rate of \$5/MWh – results in a 4.1 TWh reduction in hydro exports over the 2018 – 2021 time frame and increase in spilled energy."

In Attachment 3 the IESO states:
""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".

Figure 15 in the Evidence indicates that when HOEP is between \$15/MWh and \$20/MWh the congestion rent averages well in excess of \$5/MWH on the Michigan intertie and around \$5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.

24.1 According to Power Advisory's model hydro spill occurs when HOEP increases from \$15/MWh to \$20/MWh. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) is generally equal to or greater than \$5/MWh when HOEP is in this range. Furthermore, at this level of ICP the IESO's evidence is that an increase in ETS rates of \$5/MWh would reduce the ICP but have no impact on export flows. Does this mean that, in many instances, an increase in ETS rate of \$5.00/MWh would not reduce exports during times of surplus hydro generation (but rather reduce the ICP) and therefore would not lead to an increase in spilled energy?

24.1.1 If not, why not?

24.1.2 If yes, how has this been taken into account in Power Advisory's calculation that an increase in the ETS rate of \$5/MWh would result in a reduction of 4.1 TWh of hydro exports over the 2018-2021 time frame and correspondingly increase spill hydro energy?

25.0 Reference: Power Advisory Evidence, page 42

Preamble: The Evidence states:
"And finally, reduced exports – any point on the economic merit order – results in less market revenue paid by export traders. This reduces total market revenues and – due to the fixed cost nature of Ontario's electricity grid – increases total system costs for Ontario ratepayers. Based on historical export flows at different prices, our analysis estimates that the reduction in exports will result in a reduction in market revenues from exports of $40.8 million".

25.1 Please explain what market revenue (over and above that from ETS rates and congestion rent) the reference is referring to in terms of both the sources of revenues and who they are paid to (i.e. generators, Ontario consumers, etc.).

25.2 Please provide a schedule setting out the Power Advisory analysis that shows a $40.8 million reduction in market revenues from reduced exports due to a higher ETS rate. As part of the response please provide the source/basis for all inputs used.

26.0 Reference: Power Advisory Evidence, page 44

26.1 Please provide a schedule that sets out Power Advisory's calculation that a $1.85 reduction in the ETS rate would result in an increase of more than 10 TWh in exports over the 2018-2021 period. As part of the response please provide the source/basis for all inputs used.

26.2 Please confirm that during those times in the 2018-2021 period when an intertie was congested, reducing the ETS rate would not have increased export sold over the intertie.

26.2.1 If not confirmed, please explain why.

26.2.2 If confirmed, please explain how the calculation of the export increase took this into account.

26.3 Please provide a schedule that sets out Power Advisory's analysis that a $1.85/MWh reduction in the ETS rate would along with the calculated 10 TWh increase in exports have increased congestion rents by $111.0 million. As part of the response please provide the source/basis for all inputs used.

26.4 How does Power Advisory's calculation of the increase in congestion rents due to a decrease in the ETS rates account for the fact (per the IESO response to Exhibit I, Tab 6, Schedule 6) that ICP is only applicable during times of congestion?

27.0 Reference: Power Advisory Evidence, page 45

Preamble: The Evidence states:
"Power Advisory estimated the amount of wind curtailment that occurs when HOEP is between $0/MWh and $1.85/MWh. The analysis assumes that given the significant decline in export volumes in that range, some portion of wind curtailment would have been avoided with the lower ETS rate. Power Advisory's analysis finds that as much as 5.8 TWh of potential curtailment could have been avoided. Given the inherent uncertainty of wind curtailment, Power Advisory assumes that only 50% of that curtailment should be counted and the average market revenue would be $0.92/MWh. In total, the cost savings to Ontario ratepayers is $4.9 million".

27.1 Please provide the supporting calculations for Power Advisory's determination that "as much as 5.8 TWh of potential wind curtailment could have been avoided" if the ETS rate was reduced from $1.85/MWh to $0/MWh. As part of the response please provide the source/basis for all inputs used.

27.2 What is the basis for Power Advisory's assumption that only 50% of the curtailment should be counted?

27.3 Please provide a schedule that sets out the determination of the $0.92/MWh in average market revenue. As part of the response please provide the source/basis for all inputs used.

28.0 Reference: Power Advisory Evidence, pages 23, 33 (Figure 11), 38 (Figure 15), 41 and 45
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble: The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."

The Evidence states (page 45):
"Power Advisory estimated the amount of wind curtailment that occurs when HOEP is between $0/MWh and $1.85/MWh. The analysis assumes that given the significant decline in export volumes in that range, some portion of wind

curtailment would have been avoided with the lower ETS rate. Power Advisory's analysis finds that as much as 5.8 TWh of potential curtailment could have been avoided.".

In Attachment 3 the IESO states:
""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".

Figure 15 in the Evidence indicates that when HOEP is at $5/MWh or less the congestion rent averages in excess of $15/MWh on the Michigan interties and in excess of $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario's exports.

28.1 According to Power Advisory's model wind curtailment occurs when HOEP is $5/MWh or less (Evidence, page 41). Also, according to Power Advisory's Evidence (page 23), wind curtailment occurs when exports are constrained and unable to fully resolve surplus baseload generation. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario's two largest export markets) is greater than $5/MWh hen HOEP is in this range and at this level of ICP the IESO's evidence suggests that a decrease in ETS rates of $1.85/MWh would increase the ICP but have no impact on export flows. Does this mean that, in many instances, a decrease in ETS rate to zero would not increase exports during times of surplus wind generation (but rather increase the ICP) and therefore would not lead to decreased curtailment of wind generation?

28.1.1 If not, why not?

28.1.2 If yes, how has this been taken into account in Power Advisory's calculation that wind generation curtailment would decrease by "as much as 5.8 TWh" between 2018 and 2021 if the ETS rate was decreased to zero?

29.0 Reference: Power Advisory Evidence, page 45

Preamble: The Evidence states:
"A lower ETS will also impact exports of regulated hydro supply. Similar to the previous analysis, Power Advisory's analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range, which would capture spill at large rate-regulated hydroelectric assets. There is a significant increase in export volumes when HOEP is decreased by

$1.85/MWh within that range – meaning that a material amount of supply that may have been spilled would instead be exported. The benefit to ratepayers is more than $58.2 million over the 2018-2021 time period."

29.1 Please provide the calculations underpinning the Power Advisory analysis that "there is a significant increase in export volumes when HOEP is decreased by $1.85/MWh within that range" (i.e., $14.40MWh - $16.25/MWh). As part of the response please provide the source/basis for all inputs used and the actual calculated in increase in exports.

29.2 Please provide a schedule that sets out the determination of the $58.2 million benefit to rate payers from reduce hydro spillage. As part of the response please provide the source/basis for all inputs used and explain how Power Analysis determined the amount of increased hydro generation (i.e., reduced hydro spill) that would result from the increase in exports.

30.0 Reference: Power Advisory Evidence, pages 23, 33 (Figure 11), 38 (Figure 15) and 44
Hydro One's ETS Submissions, Attachment 3, page 12

Preamble: The Evidence states (per page 23):
"When baseload supply – the combination of nuclear, must-run hydro and wind and solar – exceeds domestic load, the province is experiencing Surplus Baseload Generation (SBG). SBG is resolved through two mechanisms. First, the energy is exported on an economic basis – i.e. energy traders purchase the energy in Ontario and sell it into a neighbouring market. Second – when SBG is more extreme – supply is either curtailed or spilled. Units at Bruce can be "maneuvered" down to reduce supply; water at hydro dams can be "spilled"; and wind and solar turbines can be "curtailed."

The Evidence states (page 45):
""A lower ETS will also impact exports of regulated hydro supply. Similar to the previous analysis, Power Advisory's analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range, which would capture spill at large rate-regulated hydroelectric assets. There is a significant increase in export volumes when HOEP is decreased by $1.85/MWh within that range – meaning that a material amount of supply that may have been spilled would instead be exported. The benefit to ratepayers is more than $58.2 million over the 2018-2021 time period."

In Attachment 3 the IESO states:

““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”.

Figure 15 in the Evidence indicates that when HOEP is in the $15/MWh the congestion rent averages well in excess of $5/MWH on the Michigan intertie and around $5/MWh on the New York interties. Figure 11 shows the Michigan and New York account for most of Ontario’s exports.

30.1 Power Advisory’s analysis focused on the impact to exports when HOEP declines by $1.85/MWh within the $14.40MWh - $16.25/MWh range. However, according to Figure 15 the average congestion rent on the interties with Michigan and New York (Ontario’s two largest export markets) appears to be equal to or greater than $5/MWh when HOEP values are in this range and at this level of ICP the IESO’s evidence is that a decrease in ETS rates of $5/MWh would increase the ICP but have no impact on export flows. Does this mean that, in many instances, and decrease in the ETS rate of $1.85/MWh would not reduce exports during times of surplus hydro generation (but rather increase the ICP) and therefore would not lead to a decrease in spilled energy?

30.1.1 If not, why not?

30.1.2 If yes, how has this been taken into account in Power Advisory’s calculation that a decrease in the ETS rate of $51.85/MWh would result in an increase in hydro energy based exports and a decrease in hydro energy spilled over the 2018-2021 time frame?

31.0 Reference: Power Advisory Evidence, pages 42-43 and 46-47

Preamble: The Evidence states (page 46)
“The time period of this analysis includes a significant and unforeseen event (the COVID-19 pandemic) that resulted in an unprecedented shutdown of large parts of the Ontario and global economies. The subsequent decline in energy consumption resulted in material instances of SBG in Ontario and surplus generating capacity in neighbouring jurisdictions. We have chosen not to remove these years (2020 and 2021) from the analysis, as we believe they provide a clear example of the benefits of the province’s interties and the dynamic nature of export pricing in dealing with unforeseen events.”

The Evidence states (page 47):

> "Since market opening, two significant domestic demand decreases have occurred (i.e., financial crisis 2008, COVID-19 pandemic). During these time periods, exports quickly helped manage supply/demand balance and mitigate the risk of enacting more expensive measures (e.g., curtailment of supply). Erecting unnecessary barriers to exports will provide a consistent disincentive to exports which removes critical tools in Ontario's tool kit to managing unforeseen system conditions. We cannot predict when the next domestic demand decrease will occur, only that it will happen and the system should be designed to ensure options are available for system operators and market participants for the benefit of Ontario ratepayers."

31.1 Please provide a schedule that breaks out the impacts set out in Table 3 for each of the years 2018-2021.

31.2 Please provide a schedule that breaks out the impacts set out in the Table on page 46 for each of the years 2018-2021.

31.3 Are there unforeseen events that could occur and result in a significant reduction in both the surplus baseload generation in Ontario and congestion on Ontario's interties?

31.3.1 If not, why not?

31.4 Both references appear to characterize the need to maintain a low (or even lower) ETS rate as insurance that will assist in managing periods of lower than expected demand. Is this a fair characterization?

31.4.1 If not, why not?

31.4.2 Should consideration be given to how much this "insurance" costs in periods when load is at expected (or higher than expected) levels and whether the "cost" is appropriate in light of the risk? How would Power Advisor recommend the OEB address this issue?

32.0 Reference: Power Advisory Evidence, page 47

Preamble: The Evidence states:

"The future of Ontario's electricity market may be very different than the last ten years, when the province experienced significant amounts of SBG and curtailment. The IESO's current forecast expects SBG to decline materially with the closure of Pickering in 2026. But the future is very much unknown and thousands of MWs of new capacity is likely to be added to the province's grid over the next decade. Depending on what type of supply is added, the risk of SBG may far higher than the IESO is currently forecasting. For example, the IESO is expected to procure new capacity on an Unforced Capacity (UCAP) basis, which may result in significant oversupply from intermittent generators in many hours. Also, recent procurement programs for the IESO – along with plans for Small Modular Reactors (SMRs) and large hydro facilities in the north – are still in their infancy".

32.1 Is it not reasonable to expect that the IESO will consider the implications with respect to surplus baseload generation when deciding what types of resources should be procured in the future?

32.1.1 If not, why not?

32.2 Please provide references for the following statements and indicate the specific timeframe in which each of the procurement activities is expected to occur: i) "and thousands of MWs of new capacity is likely to be added to the province's grid over the next decade", ii) "the IESO is expected to procure new capacity on an Unforced Capacity (UCAP) basis, which may result in significant oversupply from intermittent generators in many hours" and iii) "recent procurement programs for the IESO – along with plans for Small Modular Reactors (SMRs) and large hydro facilities in the north – are still in their infancy".