Submitted to the Ontario Energy Board

# Generic Proceeding on UTR-Related Issues and the Export Transmission Services (ETS) Rate

Board File No. EB-2021-0243

May 2022

## Expert Report for the market impacts of changes to the ETS Rate

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## 1. Introduction

1. The Ontario Energy Board ("OEB") is holding a hearing on its own motion under Sections 19, 21, and 78 of the Ontario Energy Board Act, 1998 (the "OEB Act") to consider various Issues related to Ontario's Uniform Transmission Rates ("UTR") (the "Proceeding"). The OEB assigned file number EB-2021-0243 to the Proceeding. The first phase of the Proceeding will focus on reviewing and setting the Export Transmission Service ("ETS") rate.

2. On March 24, 2022, Borden Ladner Gervais LLP ("BLG") acting as counsel to the Association of Power Producers of Ontario ("APPrO") submitted a proposal to the OEB to provide expert evidence in the Proceeding, noting:

   i. *The Proposed Expert Evidence would include a brief summary of the evidence filed on the record in this and prior ETS proceedings, however the principal focus of the evidence would be to prepare a statistical analysis on the sensitivity of Ontario exports to price changes, together with an analysis of the impact of such price changes on intertie congestion revenues and the other ratepayer benefits derived from exports.*

   ii. *In Section 4 of the IESO report titled Market Implications of the Export Transmission Service Rate dated July 2021, the IESO provides a qualitative assessment of the implications of increases in the ETS rate on various ratepayer benefits including Intertie Congestion Pricing ("ICP").*

   iii. *The Proposed Expert Evidence would seek to introduce a quantitative assessment of these implications, based on principles of statistical modelling and clearly articulated assumptions, to better inform the OEB of the potential implications of changes to the ETS rate.*

   iv. *The Proposed Experts would be asked to provide evidence to help the OEB answer questions like:*

      1. *What is likely to happen to ICP revenues and other ratepayer benefits if the ETS rate is increased to $6.07/MWh?*

      2. *What is likely to happen to ICP revenues and other ratepayer benefits if the ETS rate is decreased to $0/MWh?*

3. *What is likely to happen to ICP revenues and other ratepayer benefits if the ETS rate is maintained at the status quo of $1.85/MWh?*

3. As noted in APPrO's notice to file evidence, "the Proposed Expert Evidence will provide a clear and more robust evidentiary basis upon which the OEB can then make informed decisions on each of the issues set out in the Approved Issues List. Specifically, both the first and second issues on the Approved Issues List demonstrate an interest by the OEB in determining whether, and if so how, the ETS rate should continue to exist alongside ICP. The OEB's determination on both of these issues will be better informed following its consideration of the Proposed Expert Evidence."

4. In Its Decision on Expert Evidence and Procedural Order No. 2 issued April 1, 2022, the Ontario Energy Board accepted the proposed expert evidence made the following determination (emphasis added):

   i. *"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."*

5. On April 20, 2022 Power Advisory LLC ("Power Advisory") signed a retainer with BLG to provide evidence and testimony concerning the setting of the Export Transmission Service ("ETS") rate in Ontario as part of the Proceeding.

6. In accordance with Rule 13A.03(c) of the OEB's Rules of Practice and Procedure, BLG instructed Power Advisory to:

   i. The Company has agreed to deliver an expert report regarding the following matters (the "Report"):

      1. *a review and commentary of the evidence filed by the parties in this Proceeding as well as any other prior proceeding dealing with the ETS and related matters;*

2. *a statistical analysis on the sensitivity of Ontario exports to price changes; and*

3. *a quantitative assessment of* ***the implications of increases or decreases in the ETS rate*** *on various ratepayer benefits including Intertie Congestion Pricing and the other ratepayer benefits derived from exports, based on principles of statistical modelling and clearly articulated assumptions, to better inform the OEB of the potential implications of changes to the ETS rate.* ***(emphasis added)***

4. *This Report must be suitable for submittal to the OEB in support of APPrO's intervention in the Proceeding.*

5. *In addition, the Experts may be required to provide services in relation to the matters in Procedural Orders No. 1 and 2 filed in OEB Matter EB-2021-0243.*

7. Power Advisory has adhered to Rule 13A of the OEB Rules of Practice and Procedure (the "Rules") that "provides that an expert shall assist the Board impartially by giving evidence that is fair and objective. Additionally, an expert may give evidence in a proceeding only on issues that are relevant to the expert's area of expertise." We acknowledge and agree to Rule 13A of the Rules concerning expert evidence, and accept the responsibilities that are or may be imposed on us by that rule with respect to testimony before the OEB.

8. 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. 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.

9. The report begins with a high-level description of Power Advisory, as well as the individual authors of the report. Section 4.1 provides an overview of the ETS rate and how it has been set historically. Section 4.2

provides a high-level overview of the evidence submitted as part of this proceeding. Section 4.3. provides Power Advisory's comments on the proposed methodology from Elenchus for setting the ETS rate on a go-forward basis. Section 4.4. provides an overview of Ontario's electricity grid compared to neighbouring jurisdictions. Section 4.5. provides an overview on how prices are set on the province's interties. Section 4.6. provides an overview of export activity and volumes on the province's interties. Section 4.7. describes Power Advisory's analysis on the financial impact of raising the ETS rate by from $1.85/MWh to $6.54/MWh, as is being proposed in this proceeding. Section 4.8. describes Power Advisory's analysis on the financial impact of lowering the ETS rate to $0/MWh. Section 4.8. provides a review of Power Advisory's conclusion regarding an increase or decrease in the ETS rate.

## 2. Power Advisory Background

10. Power Advisory LLC (Power Advisory) is an energy management consulting firm with offices in Boston, Toronto, and Calgary. Power Advisory has expertise in areas including electricity market design, commercial contracting, generation procurement, conventional and renewable supply resource development, regulatory framework, power system planning, forecasting and tariff rate design. Specifically, Power Advisory provides short and long-term price forecasts for dozens of market participants in Ontario, Alberta and a range of U.S. electricity markets, including New York and New England, among others. Power Advisory's forecast is currently used in setting the Regulatory Price Plan (RPP) in Ontario.

11. Travis Lusney is the Director of Power Systems at Power Advisory. He is a Professional Engineer (P.Eng) in Ontario with over 15 years experience in the electricity sector. Travis has been an expert witness in both regulatory and commercial proceedings. Prior to working at Power Advisory, he was a Senior Business Analyst and a Transmission System Planner at the Ontario Power Authority[1], and prior to that a Distribution Engineer at Hydro Ottawa. Travis has an MSc in Electrical Engineering and a BSc in Electrical Engineering from Queen's University.

12. Travis Lusney supports clients with expertise in electricity market assessment, project development, asset valuation, and policy analysis. As a former power system planner, Travis offers clients a unique insight into electricity network needs to determine investment opportunities and risks. He is an expert in energy storage resources and their applicability to customers, grid operators, and electricity markets. Travis also has expert knowledge of power procurements having worked on various procurement initiatives. He has supported electricity buyers, such as government agencies, and participating proponents by offering a variety of professional services to support the design, implementation, and participation in procurement initiatives.

13. The curriculum vitae of Travis Lusney is attached as Appendix A.

14. Brady Yauch is the Manager of Markets and Regulatory at Power Advisory. His past experience includes working with the Independent Electricity System Operator (IESO) and regulatory work before the Ontario Energy Board (OEB). He has provided evidence as part of

[1] The Ontario Power Authority (OPA) was merged with the Independent Electricity System Operator in 2015

multiple arbitrations. He holds a Master's Degree in Economics and has more than 11 years experience in the sector.

15. Brady Yauch oversees Power Advisory's electricity price forecasts in multiple jurisdictions, including Ontario, Alberta and New York, among others. He also provides detailed economic, regulatory and due diligence analysis for a variety of clients regarding investments and strategic decisions related to the electricity sector. Those clients include market participants in jurisdictions with wholesale markets, vertical utilities, government agencies and financial firms (i.e. lenders and investment firms). He has actively participated in market design changes in Ontario over the past decade and more recently has modelled the financial impact of market design changes for a variety of clients. He has an in-depth knowledge of both the regulatory and market structure of Ontario's electricity sector. Prior to joining Power Advisory, he worked with the Market Assessment Unit (MAU) of the IESO, providing analysis on market design issues for the Market Surveillance Panel (MSP)

16. The curriculum vitae of Brady Yauch is attached as Appendix B

## 3. Summary of Evidence

17. 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.

18. Exporting energy from Ontario into neighbouring markets helps reduce total electricity-related costs for Ontario ratepayers in a number of ways. First, energy prices at the province's interties are set on a dynamic basis and often diverge materially higher than prevailing energy price in Ontario. When this occurs, export traders pay congestion rents that are used to offset a portion of transmission-related costs. Second, exports help move energy out of Ontario in hours when baseload and low-cost supply is greater than energy demand in Ontario. 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).

19. Ontario has a unique hybrid electricity market, which combines a competitive wholesale market for scheduling and real-time dispatch along with out-of-market payments that make almost all generators financially whole. These two costs are largely inversely related, as wholesale market prices decrease, out-of-market payments (recovered from Ontario ratepayers) increase. The hybrid market design in Ontario incorporates a large amount of baseload and low marginal cost generating capacity, which in many hours can exceed provincial demand. Given the baseload nature of large percentage of supply in Ontario, exporting energy into neighbouring markets provides external revenues that are used to offset fixed electricity-related costs that must be recovered from Ontario ratepayers.

20. Power Advisory analyzed the response of energy exports in the 2018 – 2021 timeframe to determine whether an increase of the ETS rate by nearly $5/MWh would be a net benefit for Ontario ratepayers. Our analysis concludes that the revenue from the higher ETS rate would be more than offset by an increase in related costs, including a reduction

in congestion rents and an increase in spilled or curtailed energy from baseload supply.

21. Power Advisory also analyzed the financial impact of reducing the ETS rate to $0/MWh. The result is a net benefit for Ontario ratepayers, as the higher congestion rents and system-wide benefits offset the reduction in ETS-related revenues. The net benefit is limited, given the smaller change (a $1.85/MWh reduction).

22. In Power Advisory's view, the current market design used to set prices at the province's intertie supports the overall economic efficiency of the grid by providing a transparent and competitive value on Ontario's energy supply. 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. All of the evidence in this proceeding is clear that export customers do not impose a cost on Ontario's electricity grid. 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.

23. The financial impact to Ontario ratepayers from increasing the ETS rate to $6.54/MWh would have been a net increase in costs of $42.6 million over the 2018 – 2021 timeframe. The increase is a result of lower congestion rents, increased curtailment at wind and hydro generators and lower market revenues from selling Ontario power in neighbouring jurisdictions. The net benefit to Ontario ratepayers of lowering the ETS rate to $0/MWh in that time frame would have been a reduction in costs of $33.7 million. The benefit results due to a decrease in curtailment and increased congestion rents.

**Table 1 Financial Impact of Increase and Decrease to ETS Rate[2]**

| | Increasing ETS Rate to $4.69/MWh | Lowering ETS Rate to $0/MWh |
|---|---|---|
| Increase/Decrease in Export Revenue | $245,050,684 | ($140,529,626) |
| Increase/Decrease in Wind Curtailment Cost | ($17,985,020) | $4,996,536 |
| Increase/Decrease in Congestion Rent | ($169,030,871) | $111,034,685 |
| Increase/Decrease in Hydro Curtailment Cost | ($59,811,638) | $58,230,547 |
| Decrease in Market Revenues | ($40,871,596) | |
| **Benefit to Ontario Ratepayers** | **($42,648,440)** | **$33,732,142** |

[2] Red indicates an increase in costs for Ontario ratepayers, while black indicates a reduction in costs.

## 4. Power Advisory's Evidence

### 4.1 *Provide a high-level overview of the ETS rate and how it has been set historically*

24. The ETS rate in Ontario has largely been set on an arbitrary basis, related more to broader transmission rate-setting decisions and settlements among parties to rate proceedings than the economic efficiency of exporting energy from the Ontario grid and the system-wide value exports provide for domestic ratepayers. Views on an appropriate ETS rate have ranged from setting it at $0/MWh to support intertie trading to advocating it be set at a high enough level to ensure it fully recovers a portion fixed transmission costs from exporters. The evolution of Ontario's electricity grid over the past decade – moving from one with large, baseload resources supported by market-based peaking plants to one with large amounts of fixed-cost, surplus, intermittent and zero marginal cost baseload supply – has altered the value that energy exports offer to Ontario ratepayers. The value of energy exports in the current electricity grid – which is now largely a fixed cost system – is vastly different than when the ETS rate was initially set in the early 2000s and into the last decade (as described in detail in this report).

25. The ETS rate was initially set at $1/MWh as part of the RP-1999-0044 proceeding – remaining at that level when the Ontario wholesale electricity market opened in May 2002. Recognizing the arbitrary nature of the initial $1/MWh charge, the OEB noted in its 2010 Decision that the "original one-dollar ETS rate was established initially as a placeholder, and was not the product of an objective, principled, or programmatic study."[3] Based on evidence filed in that proceeding that supported a "directional preference" of a higher ETS rate, the OEB increased the ETS rate to $2/MWh. In any case, the OEB acknowledged that future OEB panels should not view the $2/MWh ETS rate as having "any particular precedential value" and that "more study is required."[4]

26. In 2012, the ETS rate was subject to another detailed analysis, with the OEB ultimately maintaining the status quo rate, but directing a cost allocation study be filed by Hydro One in its next transmission rate application.[5]

[3] See Decision for EB-2010-0002
[4] See Decision for EB-2010-0002
[5] See Decision and Order for EB-2012-0031

27. As part of the proceeding in 2012, the IESO retained CRA to review a number of ETS rate options for Ontario. The CRA evidence provided five different ETS options, but placed no weight on any one particular approach. The study reviewed the impact on exports, as well as the impact on market prices and total bill amounts from changes to the ETS rate. Given the timing of the CRA evidence – when the province's supply mix was changing rapidly – it also analyzed the impact on Surplus Baseload Generation (SBG) resulting from a change in the ETS rate. A number of parties, including APPrO provided evidence in response to the CRA report. The OEB ultimately decided to keep the ETS rate at $2.00/MWh, but requested a cost allocation study to be submitted as part of Hydro One's next transmission rate application.

28. In 2014, Hydro One submitted evidence from Elenchus that sought to set the ETS rate using a cost allocation methodology, as requested by the OEB. The Elenchus evidence concluded that a $1.70/MWh rate was appropriate. 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]

29. The $1.85/MWh rate has remained in place since that time as part of subsequent transmission rate applications approved by the OEB.

30. 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. Rather, it has ranged from a simple placeholder to being part of a broader transmission application settlement agreements among parties with vastly different interests regarding transmission costs, export revenues and the role of the competitive wholesale market within the province's broader electricity sector. The evolution of the hybrid market design has further complicated the role of exports in Ontario's electricity system.

31. The methodology proposed in this proceeding relies on a traditional cost allocation methodology to justify a near four-fold increase in the ETS rate.[7] The methodology does not incorporate cost causality principles in its conclusion – neither the planning of the transmission grid or generation investments consider export demand as part of the investment planning process. The proposed methodology adopts the

[6] See the Draft Rate Order for EB-2014-0357
[7] See the current application, which is proposing an adjusted ETS of $6.54/MWh

policy of OEB's generic pole attachment proceeding as part of its justification. For reasons discussed in this evidence, the methodology is flawed and has limited analysis and discussion on the potential system-wide impacts and costs to ratepayers. The material increase in transaction costs of exporting energy from Ontario can have a negative impact on ratepayers. There is very limited discussion in the proposed methodology on whether a lower ETS rate – which supports a market-based approach to collecting export revenues through congestion rents – is more appropriate than the regulated approach being proposed as part of this proceeding. In Power Advisory's view, this is a significant shortcoming in the current evidentiary record.

### 4.2 *Provide a high-level overview of the relevant evidence that has been submitted as part of this proceeding*

32. In August 2021, Hydro One submitted a joint rate application for both its transmission and distribution businesses for the 2023 to 2027 time-period. The rate application filed by Hydro One falls under the OEB's Custom Incentive Rate-Setting ("Custom IR") framework.

33. As part of the initial joint rate application, Hydro One included updated evidence on the ETS rate. Revenue generated as part of the ETS rate is used to offset Network rate pool costs that are included in the Uniform Transmission Rate (UTR) applied to all ratepayers. The greater (less) the revenue received from exporters through the ETS rate, the less (greater) the revenue requirement related to the Network rate pool that will be allocated to ratepayers as part of the UTR.

34. As part of the joint rate application and in response to a previous OEB Decision, Hydro One provided updated evidence regarding the setting of the ETS rate. The updated evidence includes an updated cost allocation study done by Elenchus Research Associates Inc. ("Elenchus"), a jurisdictional review of current export transmission rates in other markets by Charles River Associates ("CRA") and an analysis on the implications of the ETS rate undertaken by the IESO ("IESO evidence").

35. Hydro One's joint rate application included the current ETS rate of $1.85/MWh last set in the EB-2019-0082 proceeding, but now considers a number of different cost allocation methodologies. The updated ETS rate, based on Elenchus' cost allocation methodologies, would increase the ETS rate to $3.66/MWh to as much as $6.54/MWh – potentially a nearly four-fold increase from its current level. All else being equal in

terms of energy exports, a higher ETS rate will reduce the revenue requirement included in the UTR that is collected from domestic ratepayers.

36. In Procedural Order #1 in the joint rate application, the OEB determined that a separate, generic hearing would be established to review a number of UTR-related issues, as well as the ETS rate.

37. The Elenchus evidence updated its 2014 methodology for setting the ETS rate, which relied on a "cost-based" approach. Elenchus' 2014 report concluded that only the cost of Network-related assets "dedicated" to exports should be allocated to exporters. Shared Network-related costs would not be allocated to exporters, given they operate on an interruptible service and the planning of the transmission grid in Ontario does not consider export volumes when making investment or planning decisions – i.e. export demand is not a cost driver of transmission grid (or supply, which the report did not discuss). The Elenchus evidence determined that an ETS rate of $1.70/MWh was appropriate, based on its cost allocation methodology.

38. In response to direction from the OEB – particularly the OEB's decision in the Pole Attachment Charges (EB-2015-0304) proceeding – Elenchus updated its methodology to allocate some portion of fixed Network-related costs to exporters. The Elenchus evidence concludes that the combination of reduced curtailments – i.e. the amount of interruptions faced by exporters – in recent years and the fact that exporters are "leveraging an established network" means they may be allocated some portion of shared Network-related costs. In particular, Elenchus' methodology incorporates the OEB's Decision in the Pole Attachment Charges proceeding that stated there should be no users of the Network (exporters) that act as "free riders" – i.e. leveraging value from assets while not being allocated any of its costs.

39. The Elenchus evidence then proposes three methodologies for setting the ETS rate through allocating some portion of Network costs to exporters. The three methodologies apply different portions of shared Network Asset costs between the Domestic and Export classes through the Net Fixed Assets allocator. The three methodologies allocate as much as 100% of Shared Network-related assets to exporters to as low as 50%. The different allocations are related to apportioning all of the allocated costs, an adjustment based on peak demand and an adjustment based on historical curtailments.

40. The CRA evidence provides a high-level review of ETS rates in other jurisdictions. The evidence, largely, updates a similar review the CRA provided in 2012 as part of a previous application by Hydro One. The review updates the ETS rate and incorporates a number of new jurisdictions. The CRA evidence provides limited discussion on the unique nature of export pricing in Ontario compared to other markets and whether a market-based approach or regulated approach to setting the ETS rate is appropriate.

41. Hydro One's joint rate application also included an analysis by the IESO on the implications of the ETS rate. The IESO's analysis largely focused on the operational and system-wide economic benefits for Ontario ratepayers as a result of energy exports and competitive interties with neighbouring jurisdictions.

42. The IESO's analysis expects that any increase in revenue from a higher ETS will be fully offset by a decrease in revenue from congestion rents that occur at the intertie (congestion rent is discussed in more detail in a later section of this report). A reduction in congestion rent will reduce disbursements from the Transmission Rights Clearing Account (TRCA), which are used to reduce the overall revenue requirement for Network transmission costs paid by all Ontario ratepayers.

43. The IESO's analysis also concludes that a higher ETS rate will result in "adverse" operational and economic benefits. Given the ETS is a fixed charge applied to all exports, there may be many hours where the higher ETS rate will result in an energy trade becoming "uneconomic" – it reduces or closes altogether the economic opportunity of trading between markets. 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.

44. The IESO evidence also highlights the avoided system costs that occur as a result of exports (discussed in more detail later in this report).

45. 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. More importantly, Ontario's hybrid market design is a fixed cost system. Almost all supply resources are under

contract with the IESO or are rate-regulated by the OEB. Exports are vital resource for improving the economic efficiency of the grid by introducing external revenues to reduce total-system costs that are ultimately borne by Ontario ratepayers. Further, exports can reduce system costs during temporary abnormal events where demand is severely dampened (e.g., pandemic, 2008 financial crisis, etc.).

### 4.3 *Does Power Advisory Accept the Cost Allocation Methodology Being Proposed in this Proceeding?*

46. At a high level, Power Advisory does not accept the cost allocation methodology proposed in this proceeding. There are many reasons why Power Advisory does not accept the methodology

47. First, the proposed approach does not align with cost causation principles. As Elenchus correctly notes in its evidence, Hydro One does not take exports into account when designing the transmission system and that the IESO does not factor exports into its reliability planning assessments. Simplistically, the investments by the IESO and Hydro One do not consider the unique needs, capabilities or requirements of exports. Using a cost allocation methodology without cost causality principles is wrong and should be dismissed.

48. Second, and related to the first is the concept of shared network assets that assumes each user is afforded the same considerations. The assets are not shared and have been designed, constructed and operated to meet the needs of Ontario ratepayers needs, not exporters. The simple justification that because the asset is used by exports when excess capacity is available is not reason enough to force shared rate-based costs, which are underpinned by the economic viability of the asset.

49. Third, applying principles of the pole attachment charges to exports is inappropriate, since their use of delivery assets are different. Pole attachment charges are for consistent access and use of fixed assets (in this case utility poles used by telecommunication companies). By attaching their infrastructure to existing utility poles, the third party is committing to long-term usage of the asset. Conceptually, this can be the same as purchasing a fixed amount of transfer capacity on a transmission line. Exports, on the other hand, do not make long-term fixed commitments to capacity on transmission infrastructure. Instead, exports use the system when an economic opportunity exists. This "opportunity service" targets excess capacity in the system that is being inefficiently used by existing domestic demand. The economic

opportunity can shift significantly based on market dynamics (e.g., price differential between markets) or domestic use (i.e., there is less capacity available to export). Any cost allocation methodology should recognize the economic opportunity nature of exports and that exports do not purchase a fixed amount of capacity from the system.

50. Fourth, the cost allocation methodology does not consider the potential benefit(s) to Ontario ratepayers. A cost-benefit analysis should be assessed when determining cost allocation to secondary users of the transmission system. The proposed cost allocation methodology – based on a the OEB's Decision in the pole attachment proceeding – is constructed around the concept that exports are "free riders". The use of free rider language specifically and incorrectly excludes any benefits that exports offer to rate-payers on a total system cost basis.

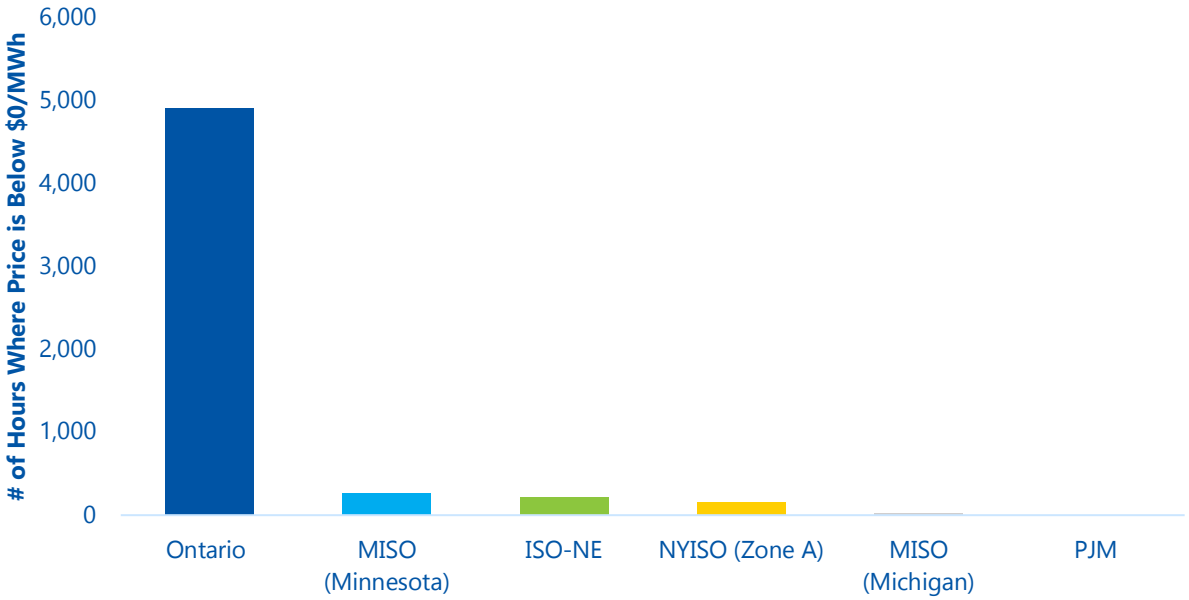
51. Fifth, and building on the fourth reason, exports play a unique role for Ontario ratepayers when domestic demand recedes both temporarily or for prolonged time periods. As Elenchus correctly notes, peak demand from domestic customers has fallen for the past decade and has not exceeded the highest peak set in 2007 of roughly 27,000 MW. During that time, exports have utilized the excess capacity in the transmission system to ship surplus or low marginal cost energy to neighbouring jurisdictions. This ensures transmission assets are being used when the system has been overbuilt. In other words, exports act as a release valve during periods where the transmission system is being under-utilized and export usage should be recognized in the cost allocation methodology.

52. During the time-period under review, Ontario was in extreme surplus baseload conditions that required exports to flow to minimize the need to curtail contracted and rate-regulated resources (as discussed at length in this evidence). The proposed cost allocation methodology and application of 12CP should recognize that system dynamic. The following graph shows the number of hours where the clearing price is $0/MWh or below in Ontario compared to neighbouring markets with major interties with Ontario. The significant price-spread between markets provided ample opportunity to export energy into higher-priced markets and reduce total system costs for Ontario ratepayers.

53. Finally, and as our evidence describes, curtailment of exports is not the only consideration for a cost allocation. Exports that do flow pay congestion rents or purchase TRs, which are remitted back to Ontario ratepayers. The cost allocation methodology being proposed in

response to the OEB's previous decision does not consider how congestion rents should be treated.

**Figure 1 $0/MWh or Below Price (2018 - 2021)**

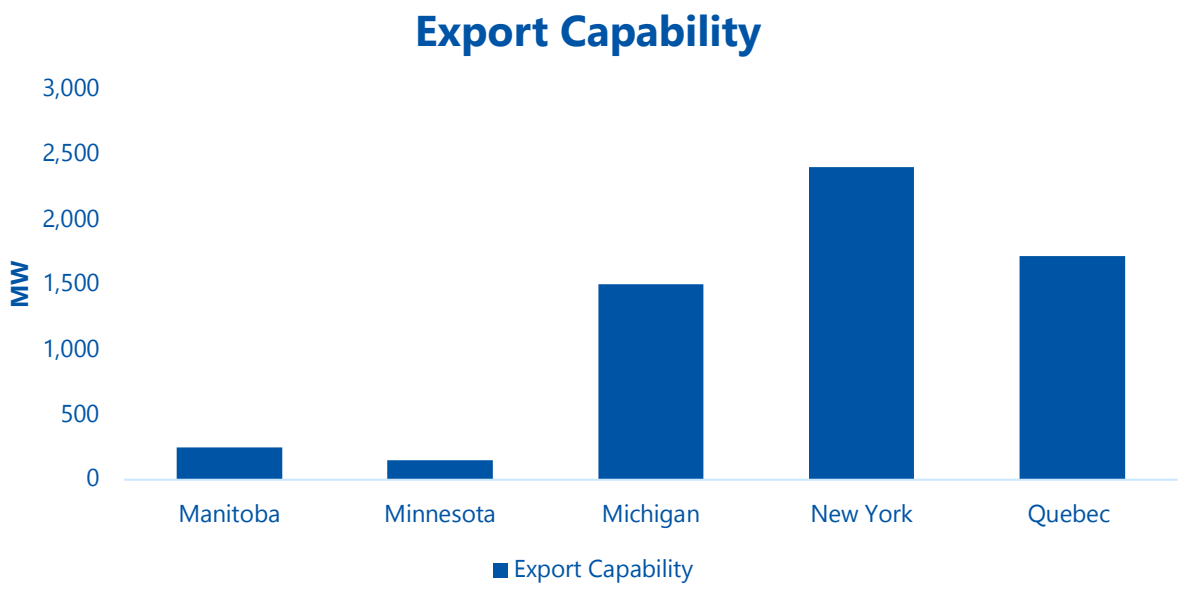



## 4.4 *Provide an overview of Ontario's supply mix and the neighbouring jurisdictions connected to Ontario's electricity grid*

54. Ontario's electricity grid is connected to numerous jurisdictions, including competitive wholesale markets (NYISO, ISO-NE and MISO) and vertically integrated grids owned and operated by crown corporations (Manitoba Hydro and Hydro Quebec). The connection to neighbouring jurisdictions and markets through physical interties allows for energy to be traded between the markets on an economic basis. In total, the interties connecting Ontario with neighbouring markets have a capacity of more than 6,000 MW, although capacity in real-time is often below that level.[8] Interties with New York (at Niagara (Zone A) and the St. Lawrence (Zone D)), Michigan and Quebec (both an HVDC connection and multiple small interties) account for the majority of the export capacity on interties.

[8] See the IESO's transmission data from its most resent APO: https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

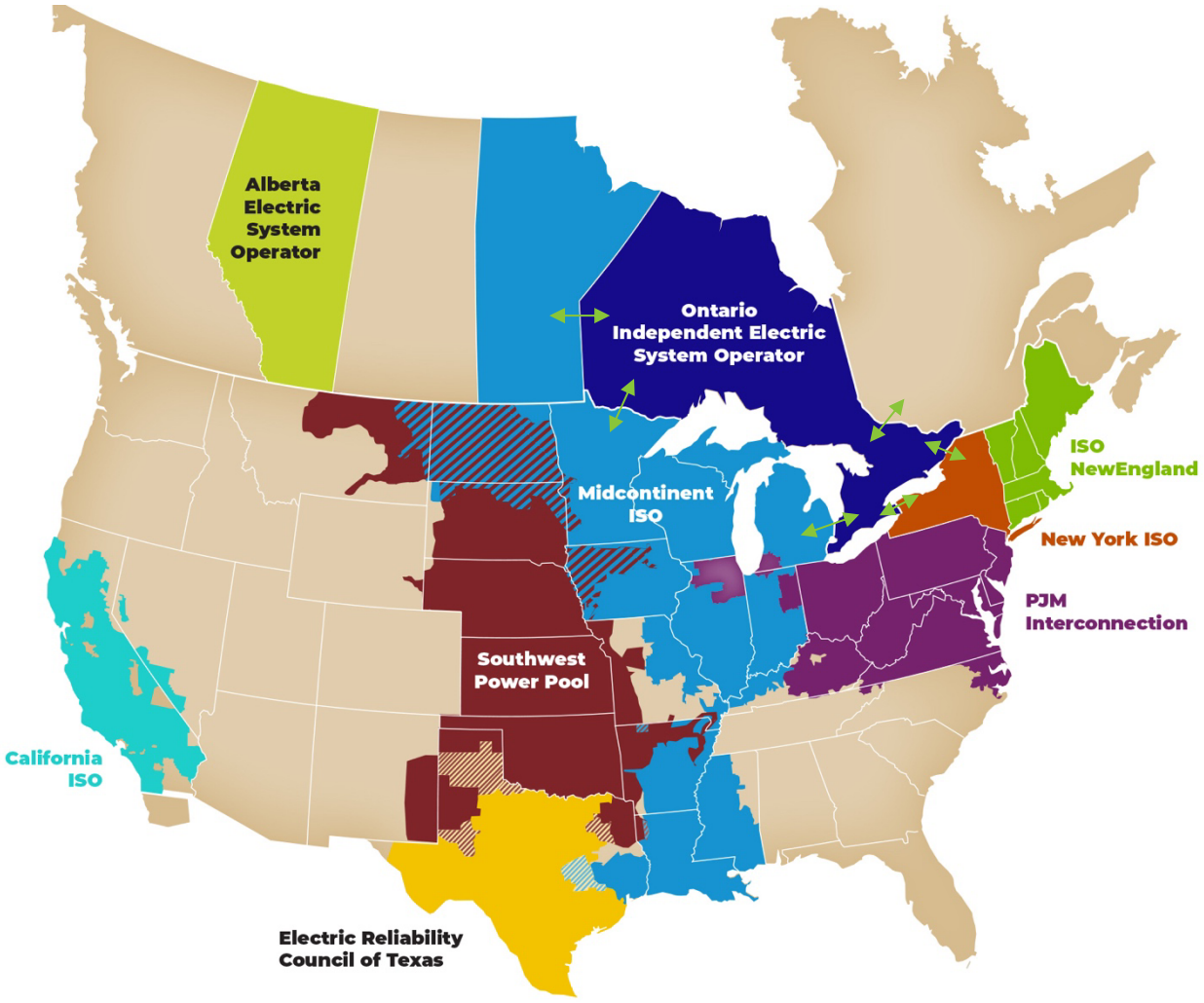
**Figure 2 Ontario's Export Intertie Capacity and Average Exports**




55. Ontario's interties allow it to directly and indirectly export energy to some of the largest electricity markets in the world. The Minnesota and Michigan interties connect Ontario directly with the Midcontinent Independent System Operator (MISO)-administered market, while the New York interties connect Ontario with the New York Independent System Operator (NYISO)-administered market.[9] The Quebec interties allow energy from Ontario to indirectly flow into the ISO-New England (ISO-NE)-administered market and, to a lesser extent, Atlantic provinces. The intertie with Manitoba allows Ontario to flow energy through Manitoba and into MISO. The Michigan intertie provides indirect access through MISO to the PJM-administered market – the largest wholesale electricity market in North America.[10]

[9] The MISO peak demand is around 120,000 MW, while New York's peak demand is 30,900 MW. Ontario's peak demand was 22,900 MW in 2021.
[10] PJM's peak demand in 2020 was more than 144,000 MW, or more than six times peak load in Ontario.

**Figure 3 Competitive Wholesale Markets in North America**




56. Ontario's electricity grid is in many respects unique both in terms of installed capacity compared to neighbouring jurisdictions with competitive wholesale markets and market design. Ontario's mix of installed capacity and hybrid market design is particularly conducive to leveraging interties with neighbouring jurisdictions to reduce system-wide costs for domestic ratepayers, while providing a dynamic approach to determining the value of Ontario's energy supply. Increasing the transactional cost of intertie trading will – all else being equal – reduce the number of opportunities for economic trading and decrease the value that energy exports provide to Ontario ratepayers.

57. Ontario has a large amount of zero marginal cost supply. Zero marginal cost supply includes baseload supply from nuclear plants, must-run hydro supply and intermittent supply from wind generators and, to a lesser extent, solar generators. Simplistically, baseload supply is limited in its ability to respond to price – nuclear units for the most part cannot

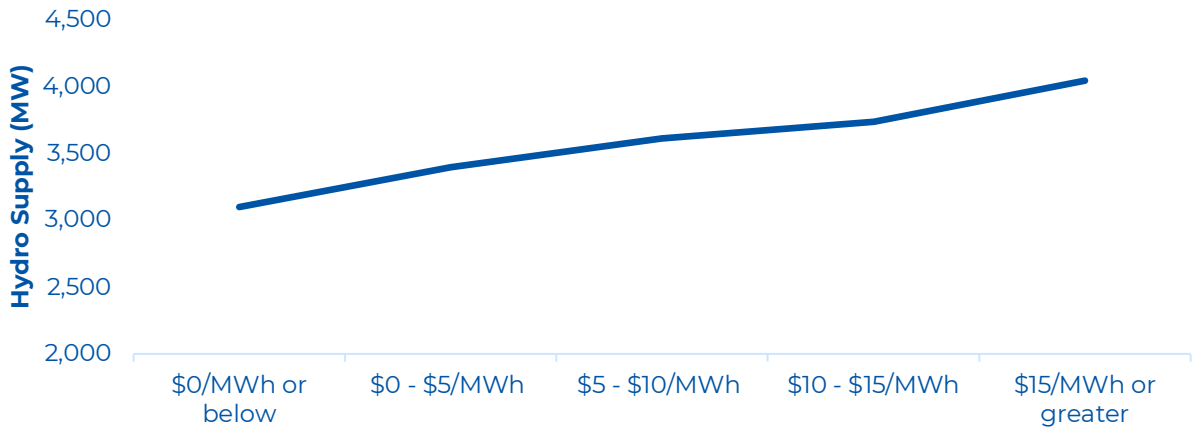
be easily shutdown and offer into the wholesale market at extremely negative prices, storage capability at hydro generators is limited and wind and solar generators generate under intermittent physical conditions and typically offer supply at $0/MWh or below. In short, baseload supply is not price-responsive and will typically offer into the wholesale market at $0/MWh or below marginal cost.

58. Consider hydroelectric supply in Ontario. Hydroelectric supply can be very flexible – storing water during low-value (i.e. low price) hours and discharging during high-value hours. Recognizing this potential, the regulated rates for Ontario Power Generation's (OPG) rate-regulated hydro assets – which amount to 6,400 MW of nameplate capacity or more than 70% of all hydro capacity in Ontario – include an explicit incentive mechanism to encourage OPG to shift energy output from low-value to high-value hours.[11] But there is a limit to the ability to store water and generate when market prices are higher, even with that incentive – there is simply a certain amount of hydro supply that is "must run" and cannot respond to price signals in the wholesale market. In the following graph, it is clear that while hydro generators have an ability to respond to price – with supply increasing as price moves higher – that ability is limited. 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.[12] 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] See the Market Surveillance Panel's report on the mechanism for a more detailed discussion: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

[12] OPG estimates that the marginal cost for its large hydro units is $14.40/MWh. See: EB-2020-0290, Exhibit A1-11-1, Attachment 1, page 14. At a high level, the marginal cost of hydro is based on its Gross Revenue Charge (GRC), which includes two charges: water rental fees and property taxes. The GRC increases with energy output.

**Figure 4 Hydro Supply Compared to HOEP**




59. The hybrid design is a unique feature of Ontario's electricity grid and differentiates it materially from neighbouring jurisdictions with competitive wholesale markets. It is commonly referred to as a "hybrid" market, as it combines a competitive wholesale market with out-of-market payments made as a result of contracting and rate-regulation. *The hybrid design results in Ontario's electricity grid largely being one of fixed costs.*

60. 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.[13] 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. Regulated hydroelectric rates are approximately $43.88/MWh, with a top-up payment made to cover the difference between revenue earned in the wholesale market and the regulated rate.[14] The combination of wholesale market revenues and out-of-market payments through the Global Adjustment (GA) is a key

[13] Most gas-fired generators are made financially whole through a monthly Net Revenue Requirement contract, which guarantees a certain amount of revenue beyond marginal costs.
[14] See the most recent payments amounts order: https://www.oeb.ca/applications/applications-oeb/opg-payment-amounts-prescribed-generation-facilities

feature of the hybrid market design. As noted, the hybrid design largely "locks in" the overall cost of supply in Ontario and reduces – or eliminates altogether – the price signal in determining investment or retirement of generating capacity in Ontario.

61. But just as important is that nearly all contracted assets are made financially whole for spilled or curtailed output. In the case of a wind turbine, if its supply is curtailed by the IESO, it – beyond a very low threshold – will be paid in full for that supply. OPG is also made whole for spilled hydro supply at its rate regulated assets. What this means for Ontario ratepayers is that these assets are, essentially, signed to a large-scale "take or pay" contract where ratepayers will pay for energy whether it is required to service domestic load or not. With Ontario's current supply mix, there are many hours where supply from rate-regulated and contracted assets is greater than domestic load and is either sold below marginal cost or curtailed.

62. 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 "floor" price in the wholesale market at which these mechanisms occur is based on whether it is nuclear, hydro or wind and solar being curtailed.[15] For nuclear maneuvers and wind and solar curtailment, the floor price is included in the Market Rules as part of the IESO-administered wholesale market. OPG's rate-regulated hydroelectric assets include a surplus generation account, which makes OPG financially whole during hours when the price is below its marginal cost. As noted previously, nearly all contracted assets – including nuclear, hydro, wind and solar – and rate-regulated hydro are made financially whole for spilled or curtailed supply.

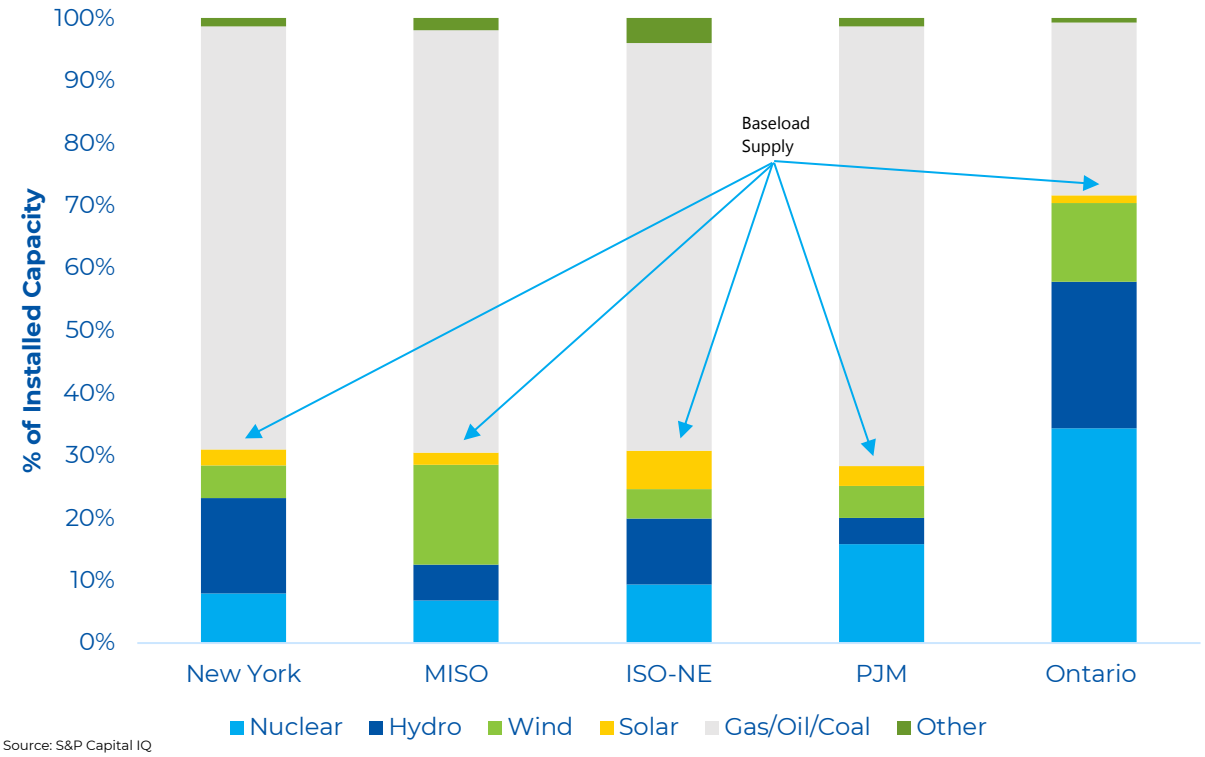
63. The key point is that Ontario has a significant amount of baseload supply that will – in many hours – push HOEP below both the marginal cost of market participants, but also significantly below contracted or regulated rates. But a low HOEP or Market Clearing Price (MCP) does not reduce overall costs for Ontario ratepayers. In contrast, given the

[15] The rules were implemented as part of SE-91. The IESO has since removed most historical documents from its website.

must-run or "take or pay" nature of this supply – where market participants are provided an out-of-market payment to make them financially whole – ensuring as much energy is arbitraged into neighbouring markets through energy exports provides a tangible reduction in overall system costs for domestic ratepayers. The hybrid market design results in a largely fixed cost electricity system – the more surplus and sub-marginal cost supply that is sold into neighbouring markets, the lower the overall system cost will be for Ontario ratepayers. External revenues help reduce costs for domestic ratepayers. Ontario's supply mix and hybrid market design stands in stark contrast to wholesale markets connected to Ontario through its physical interties, which typically operate on market-based approach and lack the hybrid top-up payments and fixed cost electricity grid that form a key feature of the Ontario electricity sector.

64. By comparing Ontario's supply mix to neighbouring jurisdictions, it's clear that energy exports play a pivotal role in providing value for domestic ratepayers. Ontario's baseload supply accounts for as much as 70% of installed capacity, while that figure is around 30% for all of the major wholesale markets that are directly or indirectly connected to Ontario's interties. Such a supply mix results in many more hours in Ontario where electricity prices are $0/MWh or lower.

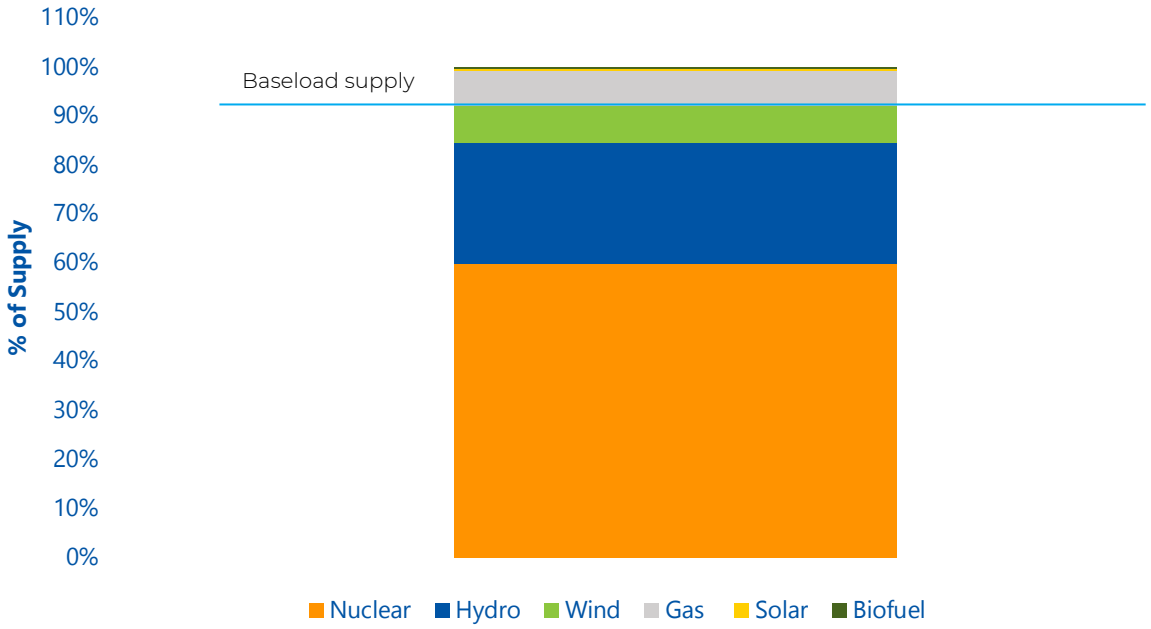
**Figure 5 Baseload supply as % of Installed Capacity**



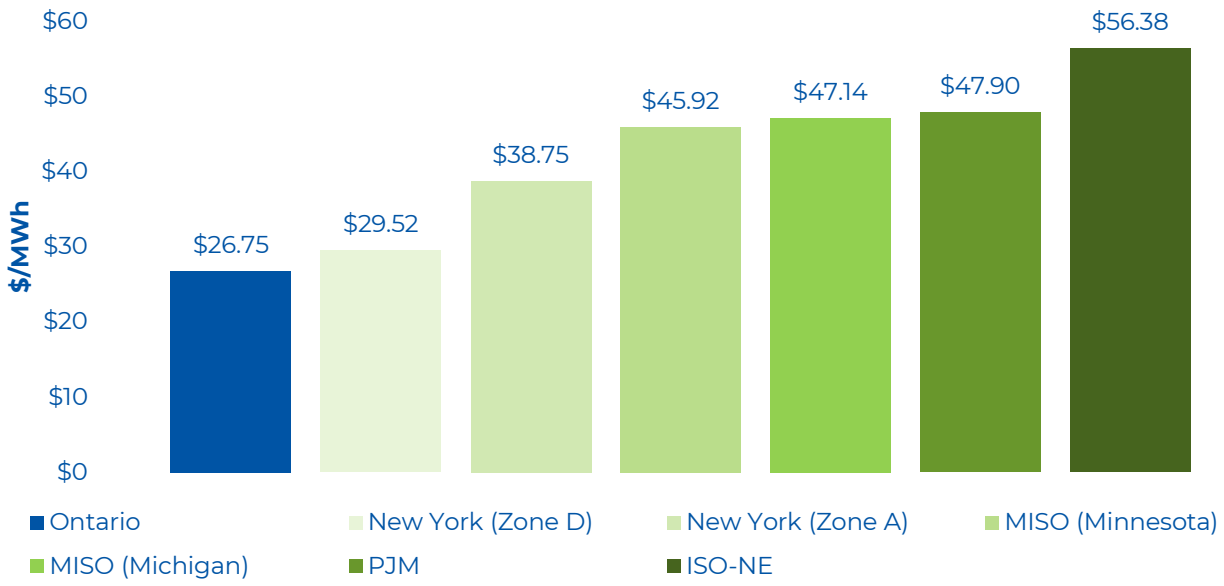

Source: S&P Capital IQ

65. When looking at actual energy output – not just installed capacity – the prevalence of Ontario's baseload supply is more extreme. In Ontario, baseload supply – including nuclear, hydro and solar – provided around 92% of all supply between 2018 and 2021.

**Figure 6 Baseload supply in Ontario as a % of Total Supply**




66. Given the high amount of baseload supply, the Market Clearing Price (MCP) and its hourly average, HOEP – in Ontario is often well below that of neighbouring jurisdictions. The following figure plots the average HOEP in 2021 compared to nearby zones in neighbouring markets. The only zone that is in any way comparable to Ontario is Zone D in New York, which includes a significant amount of baseload hydro capacity (the other half of the Saunders generating facility on the St. Lawrence and imports from Hydro Quebec), wind and material internal transmission congestion (between zones in NYISO). The NYISO market allows market participants to hedge against internal transmission constraints, so the realized price for market participants in Zone D is likely higher. Overall, Ontario prices are significantly discounted compared to neighbouring wholesale markets – providing an ideal economic landscape for arbitraging Ontario supply into higher-priced wholesale markets and reducing system costs.




## 4.5 *Provide an overview of how energy prices are set at the province's interties with neighbouring jurisdictions*

67. Energy prices on the province's intertie are set on a dynamic basis that takes into consideration "congestion" – the physical limitations of the intertie – and export bids from market participants. Intertie pricing is also a combination of pre-dispatch prices and real-time prices (although we will largely ignore this distinction for simplicity purposes).[16] We need to be clear on the difference between HOEP, the Intertie Congestion Price (ICP) and congestion rents in order to both better understand the benefits that exports provide for Ontario and the dynamic market that exists on the province's interties.

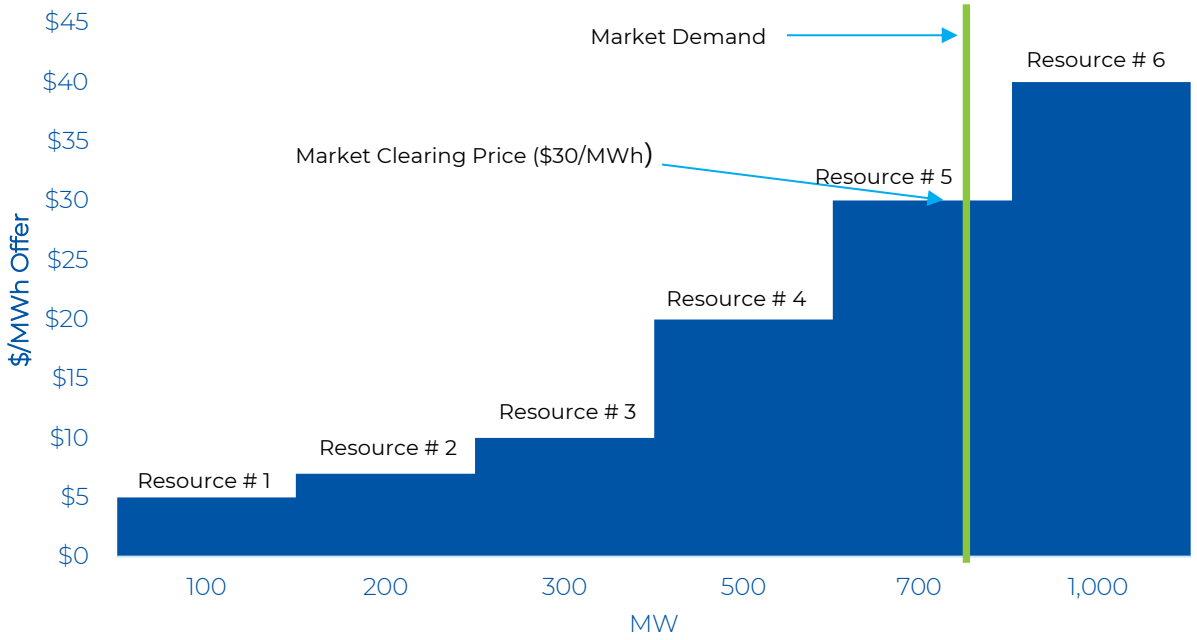
68. Generators in Ontario compete in a wholesale market to supply energy. As part of the wholesale market, generators "offer" a certain amount of power at a price of their own choosing – typically at their marginal cost. The marginal cost is the cost of producing the next incremental unit. For example, a gas-fired generator will have to purchase a certain amount of natural gas in order to produce one unit of energy. The cost of producing that first unit will be offered into the wholesale market at, for simplicity, the cost of the gas it takes to produce one MW. If the marginal cost of producing the next unit is the same, its offer will remain the same. If the next unit is more expensive to produce (i.e. it takes more gas), it will increase its marginal cost offer.

[16] Intertie congestion is determined in the hour before real-time, known as PD-1. The congestion export bids are then set at $2,000 MWh in real-time (to ensure they flow) and the congestion price determined in PD-1 is added to HOEP. Exporters take on risk that real-time prices (HOEP + congestion) differs than PD-1 prices.

Wind and solar generators are zero marginal cost supplies, as their fuel cost (the wind or sun) is free – it costs very little (or nothing) to produce a MW on a marginal cost basis for these resources.

69. The IESO "stacks" all of the marginal cost offers from cheapest to most expensive, including bids from Dispatchable Load (DL), which are large loads that will curtail demand when the MCP hits a certain threshold. This is known as the supply stack or economic merit order. The MCP is set at the intersection between demand and the supply stack. This price then becomes the price all generators are paid for their output. It is also the price that consumers pay for energy consumed during that interval.

**Figure 7 Determining the MCP in Ontario**

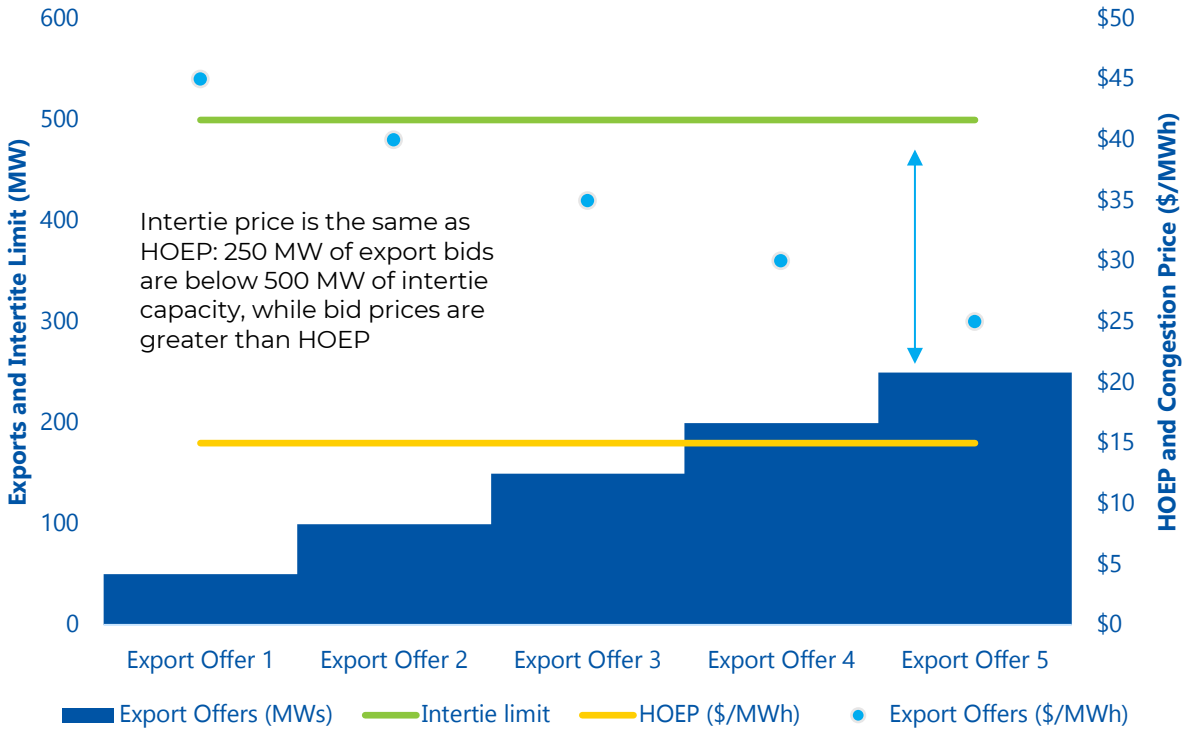



70. Prices on the province's interties are – assuming there is no congestion (discussed later) – set on a similar basis.[17] Consider the following example. The intertie has a capacity of 500 MW, with 5 export bids of 50 MW each (250 MW in total), ranging from $45/MWh to $25/MWh (export bids are stacked highest to lowest). With HOEP[18] set at $15/MWh and a lack of congestion on the intertie – i.e. the intertie is not physically constrained – all of the export bids are economic. All of the

[17] As noted, intertie prices are, in fact, a combination of pre-dispatch and real-time prices. Export bids are set in one hour prior to real-time, pre-dispatch one or PD-1. In real-time, the PD-1 schedule will flow and the congestion price determined in PD-1 will be applied to HOEP. For simplicity, we have ignored this dynamic. Exporters assume pricing risk between PD-1 and HOEP. If HOEP is higher than PD-1 and an export has been committed, it will pay the higher price.
[18] Note that we use the term HOEP, but in fact we are referring to the Ontario Zone PD-1 price.

export bids will flow in this hour (exports are completed on an hourly basis) and pay HOEP ($15/MWh) for energy to be exported. Note that export bids are stacked from highest to lowest in terms of the price that exporters are willing to pay to export energy from Ontario – the highest-priced bid is the last bid to be considered uneconomic. In this scenario, the price at the intertie is the same as HOEP, as there is no congestion. The following graph provides a visual description.

**Figure 8 Intertie Price With No Congestion**

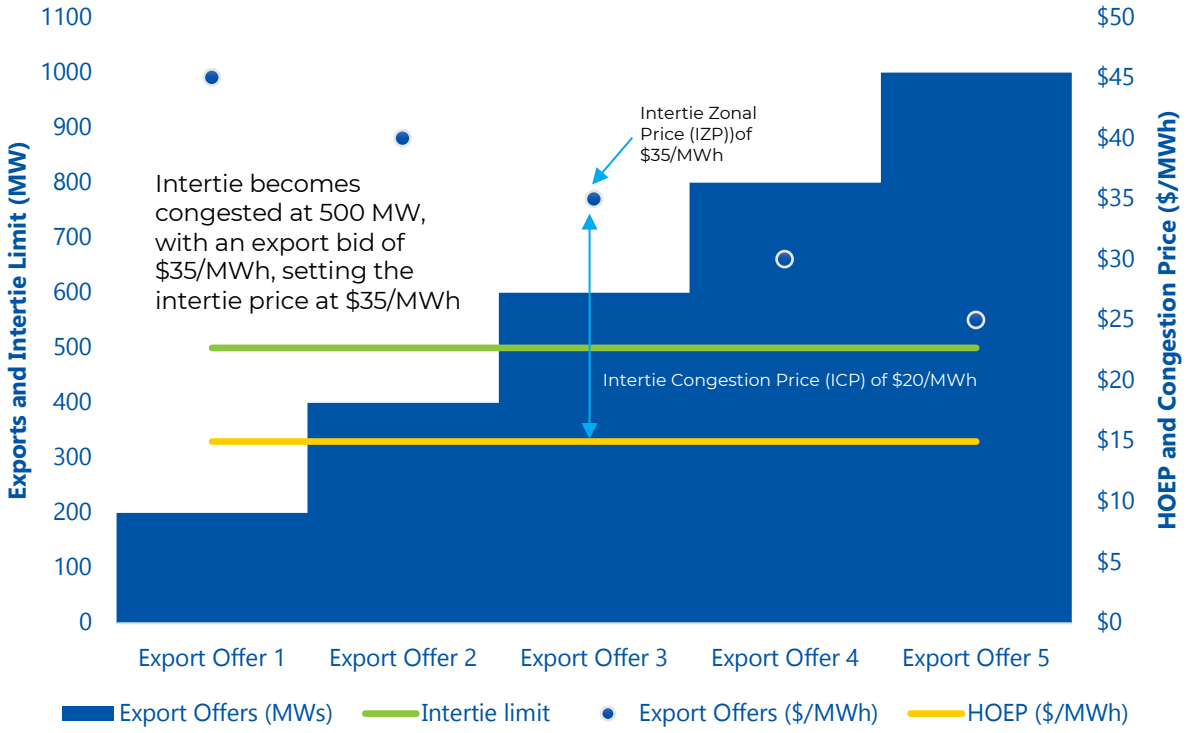



71. When the intertie is congested, the price at the intertie will diverge from HOEP and change based on export bids from market participants. Consider the following example. The intertie has a capacity of 500 MW, with 5 export bids of 200 MW each (1,000 MW in total), ranging from $45/MWh to $25/MWh (again, export bids are stacked highest to lowest). HOEP is $15/MWh. The intertie becomes "congested" at 500 MW – it has reached its physical limit. With the stacking of export bids from highest to lowest, the bid of 200 MW at $35/MWh is the last bid that clears and sets the intertie price. The difference between the intertie price – known as the Intertie Zonal Price (IZP) – and HOEP is referred to as the Intertie Congestion Price (ICP). The ICP – which is $20/MWh in this example – is considered congestion rent.

i. *Intertie Zonal Price (Exports)* – The IZP is higher when an intertie is export-constrained. This is because when an intertie is export-constrained exporters are likely willing to pay a higher value than HOEP to export energy out of Ontario. Because export bids are stacked from highest to lowest, the highest priced bids will flow and the intertie will clear once the lowest priced bid hits the intertie's physical limit. When the last unit clears, its bid sets the IZP.

ii. *Intertie Congestion Price (Exports)* – The ICP is the difference between HOEP and the export bid that set the IZP. For example, if HOEP is $3/MWh and the last economic bid was $10/MWh – meaning an exporter was willing to pay $10/MWh to flow energy out of Ontario – the ICP is $7/MWh.

**Figure 9 Intertie Price With Congestion**




72. When the intertie is congested, congestion rents are collected – the higher price that exporters pay compared to HOEP ($20/MWh) for each MWh of exports – in an account to be distributed to ratepayers. In a perfectly efficient market, congestion rents either accrue to ratepayers or are used to fund transmission expansion – essentially, funding an economic buildout of intertie capacity. Exporters can reduce congestion rents by purchasing Transmission Rights (TRs), which provide a hedge against the difference between HOEP and the Intertie

Zonal Price (ICP) by making them financially whole for any congestion rents paid. Again, in a perfectly efficient market, exporters would pay no more for Transmission Rights (TR) than the expected congestion costs they will pay to export energy.

73. The most important facet of intertie pricing in Ontario is that it is dynamic and allows market participants to adjust to real-time conditions on the grid through economic bids, while providing price transparency on both the interties and the value of Ontario's energy supply. With this market design, a low transaction cost – the fixed ETS rate in this example – encourages bidding behaviour (i.e. market competition) by market participants to determine the value of both the interties and real-time supply between Ontario and other markets.

74. The current design and low ETS rate supports price discovery through a competitive mechanism. In comparison, a higher regulated rate that allocates a portion of fixed costs unrelated to energy trading – as is being proposed in this proceeding – relies on a regulated process to determine value. A regulated process would typically only be used when there is a market failure. In this case, there is no market failure on the province's interties. Given the typical price difference between Ontario and neighbouring jurisdictions (described previously), a low transaction cost supports congestion rents on the interties – a financial benefit that ultimately accrues to Ontario ratepayers to defray the fixed cost of Ontario's electricity grid (at least in terms of transmission costs). It also increases the value of Transmission Rights (TRs). In contrast, a higher transactional cost reduces economic arbitrage opportunities, lowers the potential for congestion rents to occur and limits the ability of the province's interties to manage – and benefit from – the large amount of baseload supply that exists in Ontario compared to other wholesale markets. In short, it hampers price discovery and the dynamic, competitive environment that currently exists on the province's interties while reducing the ability of exports to reduce fixed system costs.

### 4.6 *Provide an Overview of Export Activity on the Province's Interties*

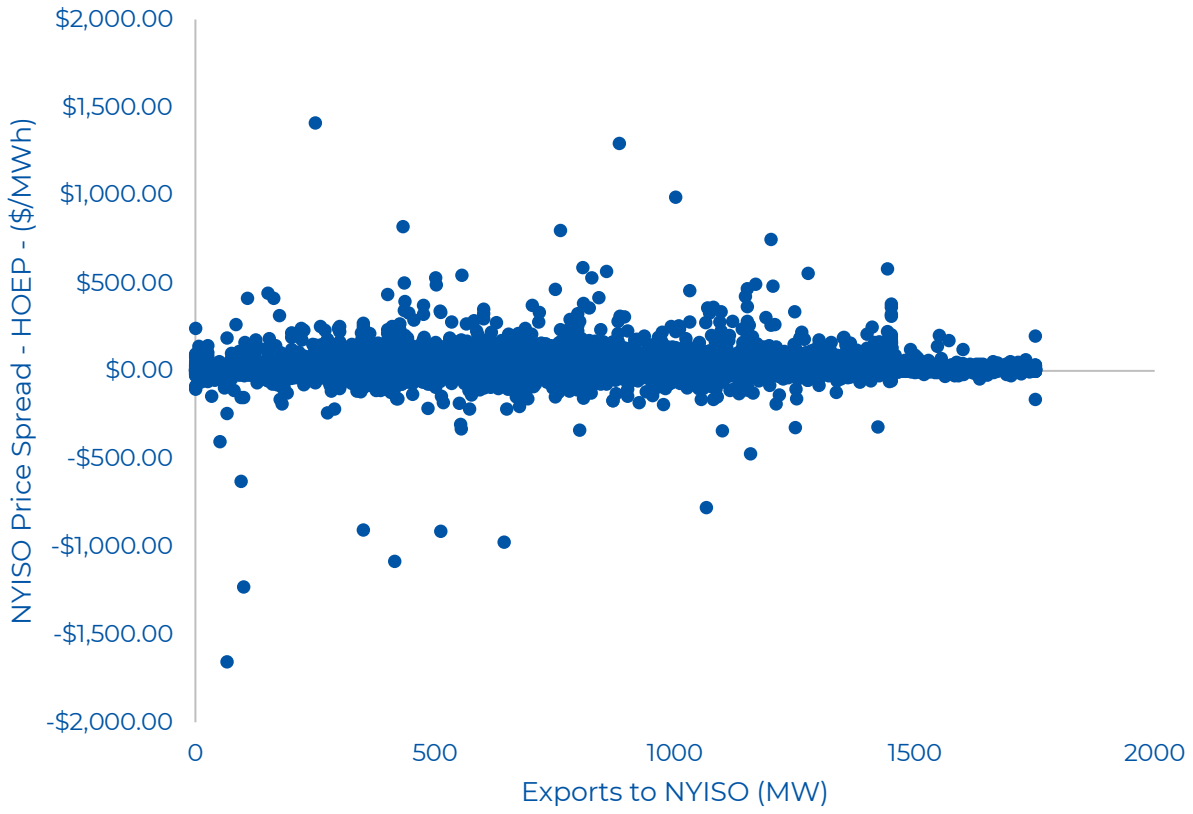
75. First, we must stress that electricity grids are incredibly complex physical networks. The financial electricity market that overlays the physical grid attempts – to the greatest extent possible – mimic the many intricacies and nuances of the physical processes that turn stored energy into power through a highly integrated network, often spanning thousands of miles. The ongoing changes and updates to the

design of electricity markets is proof that creating a financial market that perfectly emulates the physical grid is a never-ending challenge. As the grid evolves, so too does market design.

76. Understanding the complexity of energy trading is no different – as traders seek to find economic value in a highly complex real-time physical process. Energy trading occurs over multiple timelines – futures contracts years or months in advance, day-ahead markets, pre-dispatch (hours prior to real-time) and in real-time. Parsing out the economic opportunity or value on ex post basis that a particular trade is chasing is incredibly difficult.

77. As an example of the complexity of energy trading, consider the following graph. It compares energy exports into NYISO from Ontario to the spread in HOEP versus real-time prices in Zone A between 2018 and 2021. On average, the spread between the two markets over that time period was nearly $15/MWh (CAD). More importantly, it's difficult to see a clear trend on when energy exports are most likely to flow, as they occur even in hours where the spread in real-time prices between the two markets is extremely negative – meaning HOEP was significantly higher than real-time prices in New York.

**Figure 10 HOEP - NYISO Price Spreads and Exports**




78. The obvious question is: why would energy traders undertake a trade that, on its surface, makes little economic sense? The short answer relates to our previous discussion on the complexity electricity grids in general and energy trading in particular. The longer answer is more complicated.

79. First, an energy trade done in real-time might be part of a financial arrangement done in advance – whether that's a day-ahead obligation or a long-term contract done on a monthly or annual basis. If, for example, an energy trader was part of a contract to deliver a pre-determined supply for a certain time period, it may undertake the trade at a loss in the short-term to meet that obligation that could include a top-up payment to recover trading losses (similar to contracted supply in Ontario).

80. Secondly, electricity markets across the northeast and Midwest regions of North America are highly interconnected, so determining the economic arbitrage opportunity that a particular trade is chasing can be very difficult. Consider the three hours below in the following Table. The price spread between different markets in real-time can be

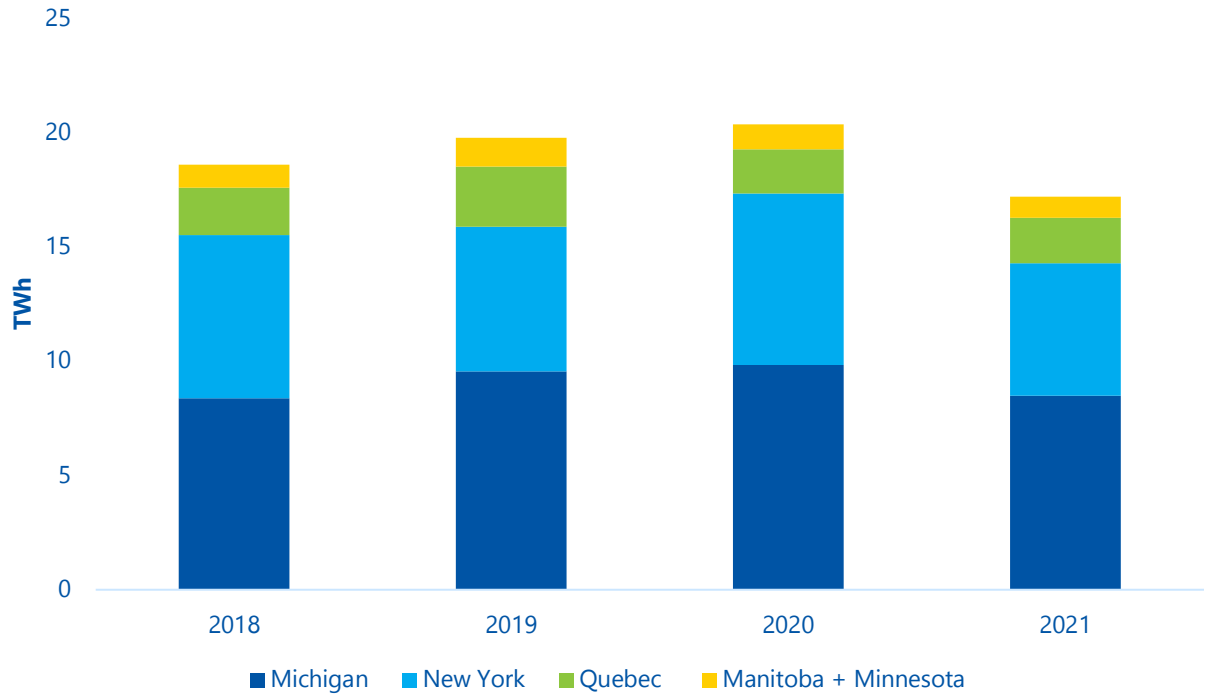
significant. Even within the same market, certain zones may experience materially higher pricing in the same hour.

**Table 2 Hourly Prices Across Zones with Competitive Wholesale Markets**

| | Ontario | NYISO (Zone A) | NYISO (ZONE D) | ISO-NE | MISO (Michigan) | MISO (Minnesota) | PJM (Com-ED ) | PJM-RTO |
|---|---|---|---|---|---|---|---|---|
| Hour 1 | **$43.69** | $39.46 | $39.08 | $49.99 | $53.08 | $32.89 | $364.11 | $299.20 |
| Hour 2 | **$224.78** | $189.36 | $183.22 | $1,026.98 | $51.50 | $37.22 | $33.06 | $42.28 |
| Hour 3 | **$42.76** | $546.82 | $163.78 | $118.02 | $48.47 | $30.06 | $46.36 | $68.67 |

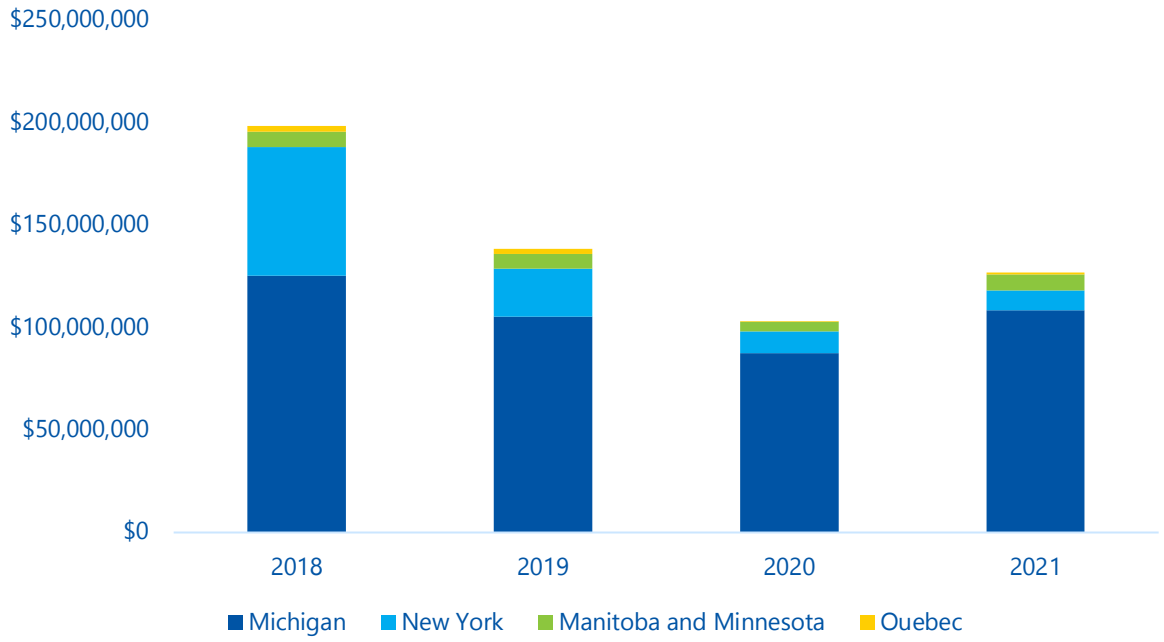
81. Ignoring the difficulty in understanding the economic viability of each, individual trade, Ontario's unique hybrid design and large amount of baseload supply – combined with flat or declining grid demand over the last decade – provides a much clearer trend regarding the economic opportunity of exporting from Ontario to neighbouring markets. The trend – regardless of the intertie – is that Ontario is a large-scale net exporter into neighbouring jurisdictions.

**Figure 11 Ontario Exports 2018 – 2021**



82. As discussed at length previously, increased export activity will often result in higher intertie prices compared to HOEP. Higher intertie prices result in greater congestion rent that will accrue to Ontario ratepayers – even with some congestion rents being avoided as a result of Transmission Rights (TRs), which act as a hedge against congestion rent. With the increase in export activity on the province's intertie has come a commensurate increase in congestion rent. Over the last four years, congestion rent from exports on the province's interties has averaged around $140 million annually, according to public data released by the IESO and analyzed by Power Advisory.

**Figure 12 Export Congestion Rent**




## 4.7 *What is the Financial Impact to Ontario Ratepayers from a Higher ETS Rate?*

83. Power Advisory's analysis using historical data concludes that between 2018 and 2021 the impact of increasing the ETS by $4.69/MWh would be to reduce average hourly exports by 160 MW and congestion rents by $169 million – although that decrease would be offset by greater total export revenues due to the near $5/MWh increase in the ETS rate. But the increase in total system costs as a result of greater curtailment would dwarf this financial benefit, by imposing $118 million in additional costs for Ontario ratepayers. In total, net system costs for Ontario ratepayers would have increased by $23 million over 2018 – 2021 time period – meaning an additional cost of $42 million that will be recovered from Ontario ratepayers.

84. The higher ETS rate imposes a significantly higher regulatory cost for exporting energy from Ontario – a cost that will have far-reaching impacts on various areas of the province's electricity sector, including the TR market, Environmental Attributes, system operations and future investment decisions at a time when the province is expected to need significant new, non-emitting capacity.[19]

85. 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.[20]

86. The first data limitation is that the IESO does not publish offer and bid data – i.e. the price/quantity pairs that market participants submit into the wholesale market to generate or consume power. Every other wholesale market in North America publishes this data in an effort to provide price transparency and support a competitive market.[21] Analyzing export bid data would provide greater clarity on the impact of a $4.69/MWh increase in the ETS.

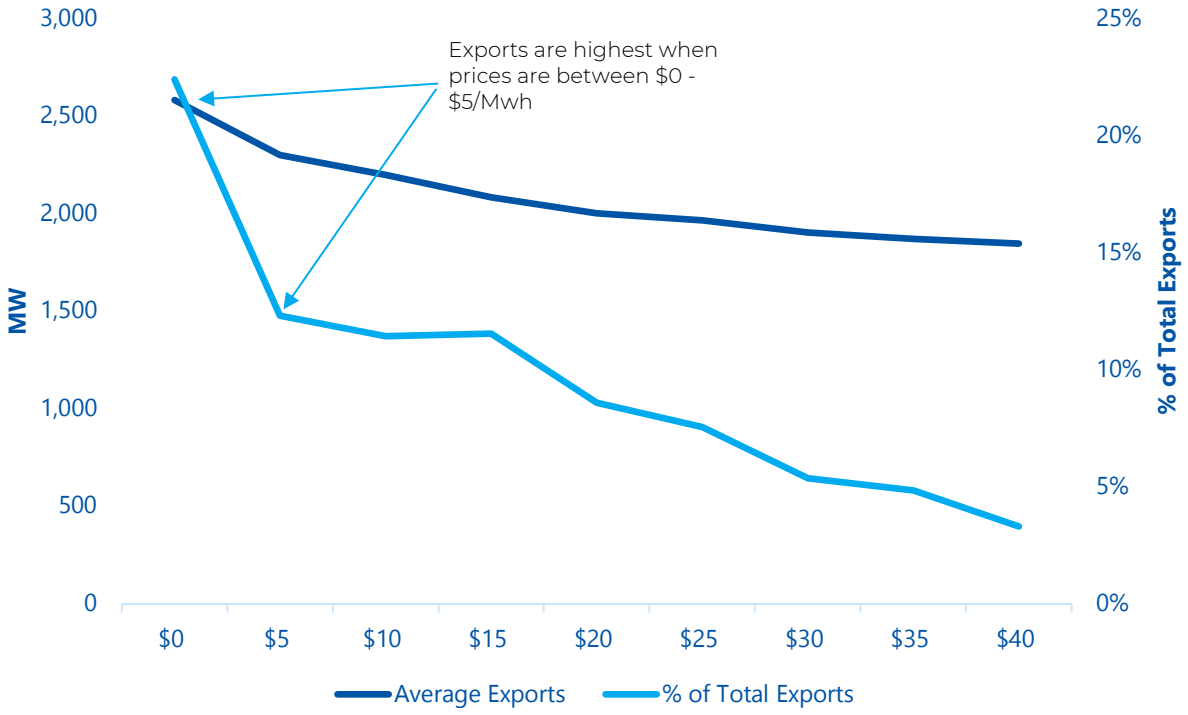
87. Second, there is a lack of data regarding curtailment and surplus energy. The IESO does not provide hourly data for these amounts. Ontario's rate-regulated and contracted hydroelectric generators also do not provide surplus volumes on an hourly basis. Surplus hydro supply is doubly bad for Ontario ratepayers, as they are charged the full regulated rate for it, while receiving no external market revenue to offset a portion of the regulated rate. In 2020, OPG recorded 4.3 TWh of surplus supply at its regulated hydro facilities – or more than 10% of its total hydro supply. Other contracted assets – notably wind assets – also do not publicly provide hourly curtailment volumes.

88. In any case, available public data of export volumes, intertie prices and HOEP, clearly show that export traders are highly responsive to prices. Analyzing data from 2018 to 2021, its evident that, as prices move higher, overall export volumes decrease. 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. More importantly, looking at exports when the Ontario price moves from $0/MWh to $5/MWh – likely when Ontario is

[19] See IESO's 2022 Annual Acquisition Report (AAR)
[20] The last detailed analysis was done by CRA in conjunction with the IESO, which would have provided more detailed data.
[21] FERC has mandated it in most cases.

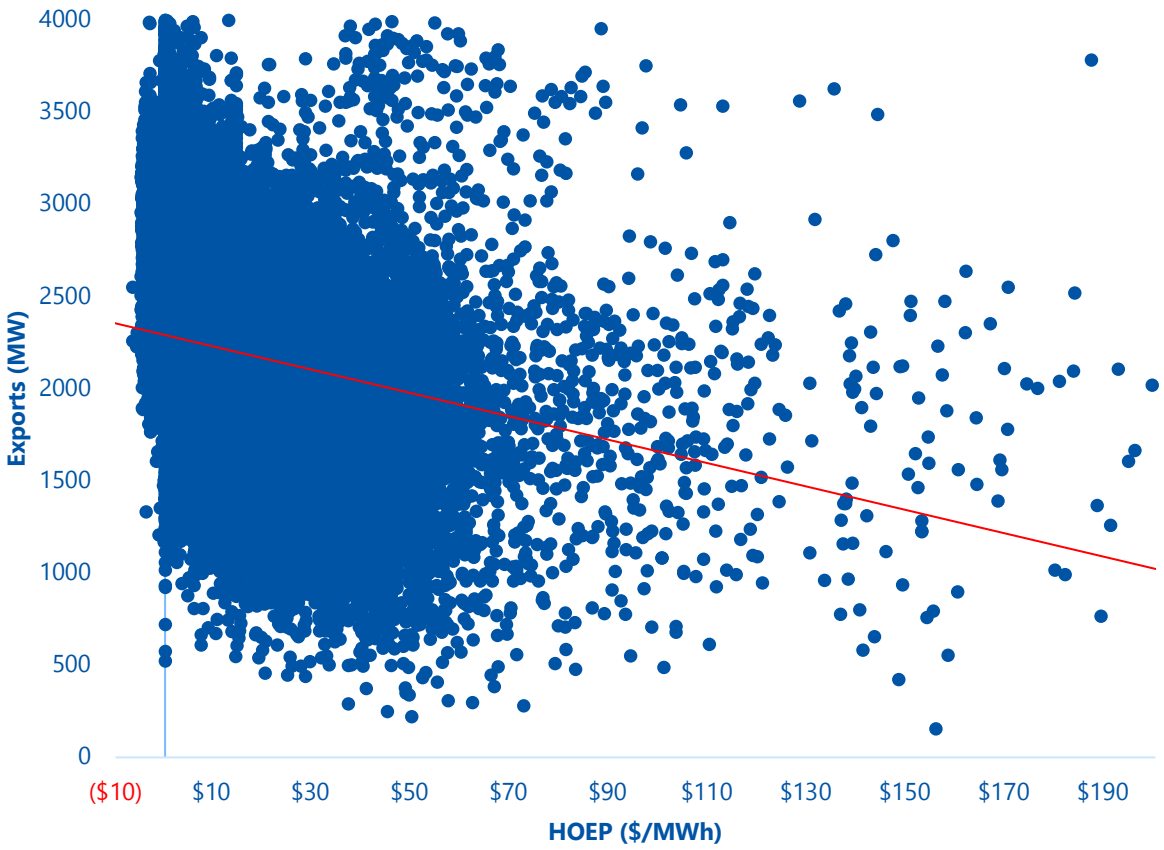
experiencing severe SBG and curtailment – hourly exports decrease, on average, by nearly 280 MW. Total exports between 2018 and 2021 when HOEP was $0/MWh were more than 13 TWh, falling to 7 TWh when HOEP increased to $5/MWh.

**Figure 13 Average Hourly Exports by Price**




89. Analyzing more granular data shows a similar result (shown in the following graph).

**Figure 14 Exports by HOEP[22]**

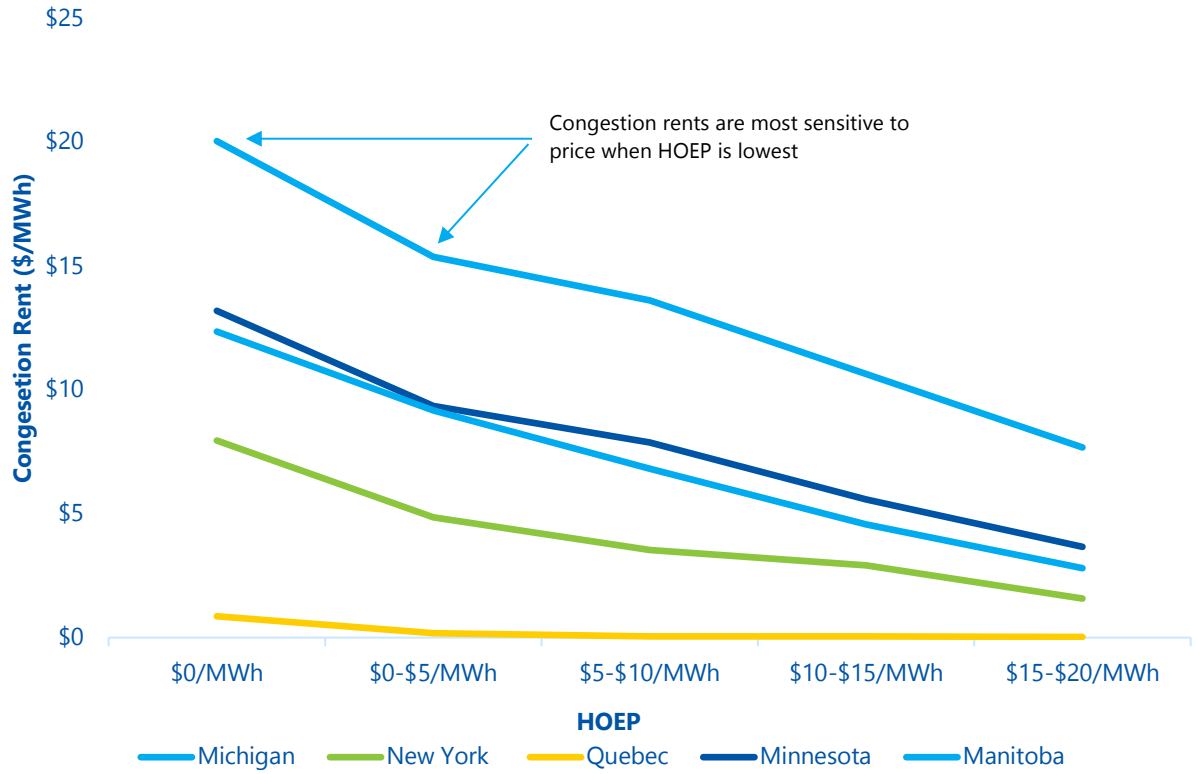



90. A certain level of exports from Ontario will, on average, occur regardless of price – with there being an average of nearly 2,100 MW of exports per hour throughout the time frame. The reason for a near steady-state of exports is a combination of factors. First, export volumes include wheel-through transactions, which are a simultaneous import and export of energy – (a trader offers an equivalent amount of imports and exports in the same hour). Second, export trades may be done on an uneconomic basis when they are part of a long-term contractual agreement, as discussed previously. And finally, Ontario – as noted previously – has a lower marginal cost system compared to neighbouring markets. In hours when demand is high – cold winter evenings or hot summer afternoons – most of the electricity grids connected to Ontario will also be experiencing high demand. Given the low marginal cost of Ontario's supply, it is very often economic to export in hours even when HOEP is above average, as it is similarly elevated in neighbouring jurisdictions.

[22] The redline is a linear trendline

91. 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).

**Figure 15 Congestion Rent Compared to HOEP**




92. Export traders are price-responsive. With an expected increase in the ETS rate from its current level to as much as $6.54/MWh, both the amount of exports that will flow out of Ontario and the congestion rent that exporters will pay to move energy is also expected to decline. The impact on congestion rents is most dramatic when HOEP is between $0/MWh and $20/MWh, as that is when the system benefit to Ontario ratepayers is greatest (discussed later) and exports are highest.

93. The first impact of the higher ETS rate will be a reduction in total export volumes. Based on exports between 2018 and 2021, a $4.69/MWh increase in the cost to export energy from Ontario will reduce exports by more around 17.0 TWh – declining from 75.9 TWh to 58.9 TWh. The revenue impact of that decline is actually beneficial for ratepayers, as

the higher ETS rate more than offsets the revenue impact from lower export volumes:

*1.a. Current ETS Revenue:* $1.85/MWh * 75.9 TWh = $140.5 million

*1.b. Expected Revenue based on lower export volumes and higher ETS rate:* $6.54/MWh * 58.9 TWh = $385.5 million

*1.c. Financial Impact from Reduced Export Volumes:* 1.b. – 1.a. = $245.0 million

94. Congestion rents will also be impacted by the increase in the ETS rate. The reduction in congestion rent totals $169.0 million – falling to $397.9 million from $567.0 million, or a near 30% decline, in congestion rent collected.

*2.a. Congestion Revenue with current ETS Rate:* $567.0 million

*2.b. Decrease in Congestion Revenue with $5/MWh increase in ETS Rate:* -$169.0 million

*2.c. Total Export Congestion Revenue:* $567.0 million - $169.0 million = $397.9million

95. Combining the two impacts results in a net benefit to Ontario ratepayers of $76.0 million:

*3.a. Export and congestion rent impact of higher ETS rate:* 1.c + 2.b. = $76.0 million

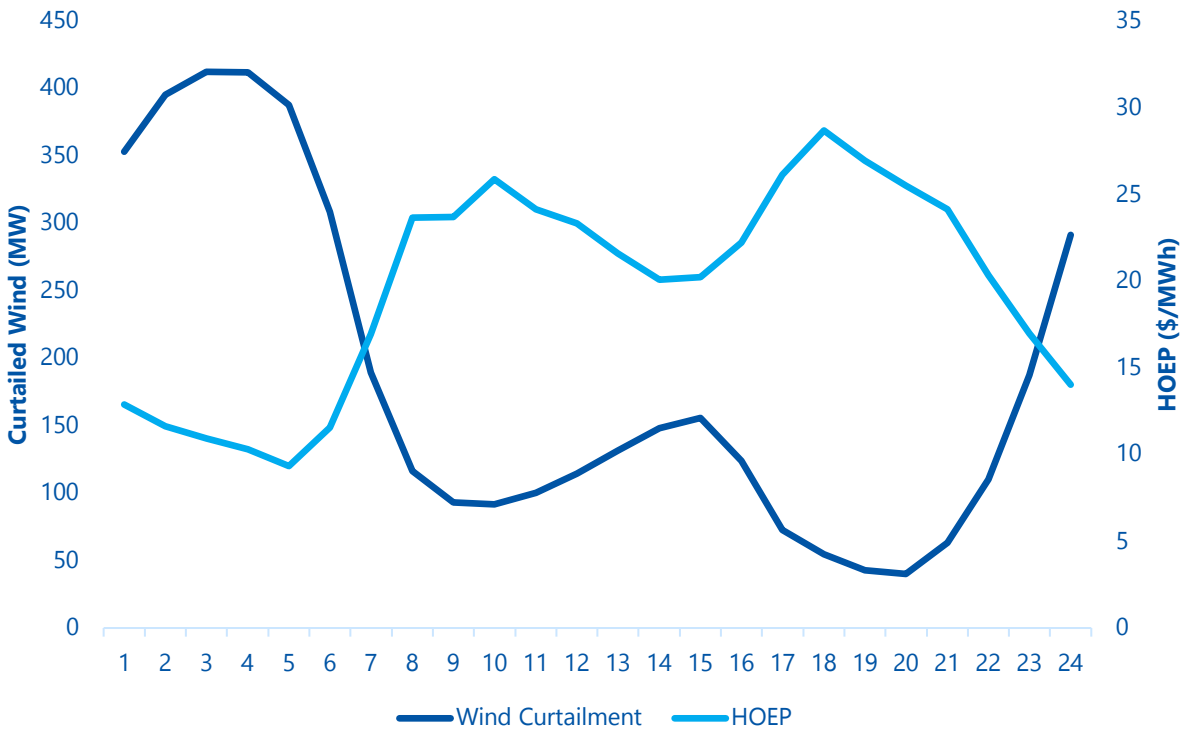
96. But the financial benefit from a higher ETS rate on export volumes, which offsets the decline in congestion rents, is more the offset by the increase in total system costs that will now be allocated to domestic ratepayers, rather than paid for by customers in neighbouring jurisdictions. Note in our previous discussion that Ontario's hybrid design is, in nearly all aspects, a fixed-cost system. Few, if any, market participants rely solely on the wholesale competitive market for their revenues.

97. Power Advisory's analysis focuses on the financial benefit of reducing curtailment at the province's transmission-connected wind assets and OPG's rate-regulated hydro assets, which total around 5,000 MW and 6,400 MW of installed capacity, respectively.

98. As noted previously, wind and most hydro generators do not rely solely on market revenues. 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). As noted previously, if HOEP is $10/MWh and the CfD rate is $135/MWh, the wind asset owner will receive a $125/MWh out-of-market payment to make them financially whole.

99. For obvious reasons, wind generators have little control over when they can provide supply – supply is fully dependent on the intermittent nature of wind speeds. As a result of intermittent wind speeds and prevailing wind patterns, wind curtailment, on average, occurs in hours with moderate grid demand and low prices. The following graph plots average wind curtailment against HOEP. 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.

**Figure 16 Average Wind Curtailment Versus HOEP by Hour**




100. Just as important is that most wind CfD contracts provide a payment for curtailment. As a result of an update to the market design, the IESO made all wind generators "dispatchable", while implementing a floor

price, in an effort to maintain the economic efficiency of dispatch in the wholesale market.[23] As part of the agreement to include floor prices, most contracts were updated to include a curtailment clause. At a high level, the curtailment clause protects wind generators from a majority of curtailment – meaning wind asset owners are made financially whole even when the IESO curtails supply from wind turbines. 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).

101. 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.

102. 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. When HOEP is below $15/MWh, flexible supply from OPG's large hydro facilities will not be economically dispatched – instead, this supply is targeted for export markets or spilled and compensated. The amount of supply that is exported will be a combination of must-run supply and the intertie capacity – i.e. OPG will store what is physically possible or can by physically (and economically) accommodated by interties.

103. When the ETS rate is increased by $4.69/MWh, it results in a simultaneous impact of reducing export demand – by shrinking the potential for arbitrage – and resulting in greater spilled supply. With the combination of a regulated rate and surplus baseload generation, reducing exports of regulated hydro supply increases total system

[23] See SE-91 by the IESO: https://rise.esmap.org/data/files/library/canada/RE%20Q8.3/Renewable-Integration_Completed-Engagement.pdf

costs for Ontario ratepayers. 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.

*4a. Cost of Increase in Spill at OPG's Regulated Hydro Assets:* 4.1 TWh X $14.40/MWh = -$59.8 million

104. 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. Note that to avoid double counting, this figure does not include the financial impact captured in the wind curtailment and spilled hydro calculations. It also doesn't include any impacts when HOEP is greater than $100/MWh, as it is less clear that a higher ETS will have a material impact in those hours (export volumes when HOEP is greater than $100/MWh accounted for less than 1% of total exports).

105. Combining the various impacts from moving the ETS rate from its current level of $1.85/MWh to $6.54/MWh, the total impact to Ontario ratepayers is net benefit of -$42.6 million – amounting to net increase in total system costs. The largest individual impact is the reduction in congestion rent as a result of less exports and less congestion on the province's interties.

**Table 3 Financial Impact of Higher ETS Rate**

| | | Financial Impact (2018 - 2021) | Calculation |
|---|---|---|---|
| a). | Total Congestion Rent | $567,017,643 | |
| b). | ETS Revenue at $1.85/MWh | $140,529,626 | |

| | | | |
|---|---|---|---|
| c). | Decline in Export Volumes From ETS Increase to $6.54 (MWh) | 17,004,726 | |
| d). | Export Volumes with $6.54 ETS Rate (MWh) | 58,957,234 | |
| e). | ETS Revenue with $6.54 ETS Rate | $385,580,310 | d). x $6.54/MWh |
| f). | Difference in Export Revenues With Current vs Proposed ETS Rate | $245,050,684 | e). - b). |
| g). | Ontario Ratepayer Impact from Curtailed Wind Supply | ($17,985,020) | |
| h). | Reduced Market Revenues from Lower Exports with $6.54/MWh ETS Rate | ($40,871,596) | |
| i). | Lower Congestion Rent as a Result of $6.54/MWh ETS Rate | ($169,030,871) | |
| j). | Financial Impact of Increased Hydro Spill | ($59,811,638) | |
| k). | Total Impact of $6.54/MWh ETS Rate | ($287,699,125) | g). + h). + i) + j). |
| l). | Net Impact to Ratepayers | ($42,648,440) | f). + k). |

106. Furthermore, given Ontario's unique cost allocation design, an increase in total system costs will not impact all ratepayers the same. The financial impact will be greater for small-volume ratepayers – referred to as Class B customers, which includes all residential and small-business consumers – due to how fixed systems costs are allocated. Large-volume consumers – known as Class A consumers – will disproportionately benefit from the shifting of system costs away from market revenues.

107. As part of the Industrial Conservation Initiative (ICI), large-volume consumers pay Global Adjustment (GA) costs based on their demand during the peak five demand hours in the previous year.[24] If a Class A consumer does not consume any power during the highest demand hours, it will not be charged any Global Adjustment (GA) costs, which are a proxy for the fixed cost of the electricity grid that is not recovered through the wholesale market. As exports decline, the combination of lower market prices (due to lower export demand and higher surplus or sub-marginal cost supply) and less external revenues, will increase the percentage of system costs that must be recovered from domestic ratepayers. When Global Adjustment (GA) payments are reduced for Class A customers, those costs are transferred to Class B customers. All else being equal, a reduction in market prices and market revenues will increase Global Adjustment (GA) charges and, subsequently, Class B rates for all small-volume ratepayers.

[24] See the Market Surveillance Panel's report on the ICI program: www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

## 4.8 *What is the Financial Impact of Lowering the ETS Rate to $0/MWh*

108. Power Advisory's analysis also used historical data to assess the impact on costs for Ontario ratepayers from lowering the ETS rate from $1.85/MWh to $0/MWh. The financial impact resulting from that decrease would be a net benefit to Ontario ratepayers of $33.7 million. The benefits are a result of increased congestion rent and reduced curtailment from wind turbines and hydroelectric supply.

109. Again, using HOEP as a proxy for changes to export volumes, a decrease in the ETS rate from $1.85/MWh to $0/MWh results in an increase in export volumes of more than 10 TWh – increasing from around 75.9 TWh to 86 TWh. Given the $0/MWh ETS rate, the increase in exports at $0/MWh results in lower revenues for Ontario ratepayers.

> *1.a. Current ETS Revenue:* $1.85/MWh * 75.9 TWh = $140.5 million
>
> *1.b. Expected Revenue based on lower export volumes and higher ETS rate:* $0/MWh * 86 TWh = $0
>
> *1.c. Financial Impact from Reduced Export Volumes:* 1.b. – 1.a. = -$140.5 million

110. Congestion rents will be impacted by the decrease in the ETS rate. Power Advisory's analysis focused on the impact to congestion rents when HOEP decreases from $1.85/MWh to $0/MWh. Exports within this price range account for nearly 17% of all export volumes, while congestion rents total nearly 25% of all rents. The increase in congestion rent totals $111.0 million – increasing to $678.1 million from $567.0 million in congestion rent collected over the 2018 – 2021 time period.

> *2.a. Congestion Revenue with current ETS Rate:* $567.0 million
>
> *2.b. Increase in Congestion Revenue with $1.85/MWh decrease in ETS Rate:* $111.0 million
>
> *2.c. Total Export Congestion Revenue:* 2a. + 2b. = $678.1 million

111. Combining the two impacts results in a net benefit to Ontario ratepayers of -$29.0 million:

> *3.a. Export and congestion rent impact of lower ETS rate:* 1.c + 2.b. = $29.5 million

112. But the financial loss from a lower ETS rate is more the offset by the decrease in total system costs that are currently fully allocated to domestic ratepayers. Similar to the previous analysis, the two primary financial impacts are reductions in wind and hydro curtailment.

113. 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.

114. 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.

115. Taken together, lowering the ETS rate from $1.85/MWh to $0/MWh provides a net benefit to Ontario ratepayers of $33.7 million over the 2018 – 2021 time period – or $8.4 million annually.

**Table 4 Financial Impact of Decreasing ETS to $0/MWh**

| | | Financial Impact (2018 - 2021) | Calculation |
|---|---|---|---|
| a). | Total Congestion Rent | $567,017,643 | |

| | | | |
|---|---|---|---|
| b). | ETS Revenue at $1.85/MWh | $140,529,626 | |
| c). | Increase in Export Volumes From ETS Decrease to $0/MWh | 10,044,775 | |
| d). | Export Volumes with $0 ETS Rate | 86,006,735 | |
| e). | ETS Revenue with $0 ETS Rate | $0 | d). x $0/MWh |
| f). | Difference in Export Revenues With Current vs $0 ETS Rate | ($140,529,626) | e). - b). |
| g). | Cost Savings from Reduced Curtailed Wind | $4,996,536 | |
| h). | Increased Congestion Rent as a Result of $0/MWh Rate | $111,034,685 | |
| i). | Financial Benefit of Reduced Hydro Spill | $58,230,547 | |
| j). | Total Impact of $0/MWh ETS Rate | $174,261,768 | g). + h). + i). |
| k). | Net Impact to Ratepayers | $33,732,142 | j). + f). |

### 4.9 *What is Power Advisory's Conclusion Regarding a Higher or Lower ETS Rate?*

116. Overall, a large increase in the ETS rate will likely increase total system costs that will have to be recovered from Ontario ratepayers and result in higher rates. While the shifting of fixed costs to exporters through a higher ETS rate may initially appear to be beneficial for Ontario ratepayers, the reality is that it may reduce the province's ability to economically manage its baseload and sub-marginal cost supply, leading to greater curtailment (and domestic costs). Additionally, a reduction in exports will reduce the province's ability to generate economic rents on the province's interties, which help defray a certain potion of fixed system costs. While a portion of congestion rent is offset through the sale of Transmission Rights (TR), a higher forecast of congestion increases the price of Transmission Rights (TRs) and vice versa – meaning the increase in the ETS and reduced congestion prices is expected to result in lower prices in the Transmission Rights (TRs) auction.

117. Conversely, a reduction in the ETS rate to $0/MWh over the 2018 to 2021 time frame is likely to have reduced total system costs for Ontario ratepayers.

118. 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.

119. 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. It is too early to fully determine whether SBG – and the value that exports provide for Ontario ratepayers – will no longer be a material concern going forward. Increasing the transactional cost of managing the province's baseload supply may severely limit the province's ability to economically manage its supply.

120. Broadly, the future is inherently uncertain. System planners, market participants, regulators and policy makers must have release valves available to manage unforeseen circumstances. A primary reason why reliability planning by the IESO does not include interties is because they are left as a margin of safety should the future not materialize as expected. In particular, exports provide an immediate ability to manage system costs for customers when domestic demand decreases unexpectedly. 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.

121. Finally, we strongly support the current design of intertie pricing that introduces a dynamic pricing mechanism that provides a clear price signal for the value of Ontario's energy supply. Under this market design, which includes hundreds of millions of dollars in congestion

rents, exporters have relied on a competitive mechanism to transparently value Ontario's energy supply and intertie capacity. Introducing a materially higher transactional cost through an increased ETS rate, replaces this competitive and transparent price signal with a regulated rate. This regulated rate is an attempt to shift a portion of Ontario's fixed costs onto export customers who are not – a point that all of the parties in this proceeding appear to agree – a cost driver in Ontario's grid and does not appear to be addressing a clear market failure. In fact, exports help reduce total system costs and are a net benefit to Ontario ratepayers. A higher ETS – acting as a proxy for a new regulated rate for export customers – is expected to undermine the benefit that exporters provide for Ontario ratepayers.

Travis Lusney

Director, Power Systems

May 27, 2022

Brady Yauch

Manager Markets and Regulatory Affairs

May 27, 2022

## APPENDIX A. METHODOLOGY

Power Advisory's methodology relied on a statistical review of exports, congestion rents and curtailment volumes in a range of price points.

1. The first step of the analysis was to collect HOEP, exports, intertie prices and wind output (for all turbines) data for the 2018 to 2021 time frame.

2. Congestion rents were then calculated based on the difference between intertie prices and HOEP for each unit of export volumes. In reality, congestion prices are set using PD-1, but that information was not publicly available on a historical basis, so HOEP was used a proxy to calculate congestion rents. While HOEP and PD-1 prices can diverge, they are typically within a close range. In 2021, the average spread between HOEP and PD-1 was $3/MWh.

3. Total congestion rents and export volumes were then calculated using varying price ranges in HOEP. For example, given the proposed increase in the ETS rate of $4.69/MWh (moving from $1.85/MWh to $6.54/MWh), the analysis calculated the difference in rents and exports volumes in $4.69/MWh price ranges. For example, exports were calculated when HOEP was $0/MWh - $4.69/MWh, $4.70/MWh - $9.38/MWh and so on. Note that $0/MWh prices included those down to -$0.1/MWh given the large number of hours where price was withing -$0.1 - $0/MWh. The price ranges were used as a proxy for increasing the ETS rate by the proposed amount.

4. The difference between export volumes and congestion rents based on varying price spreads were then used as the basis to determine the impact both on exports and congestion rents collected with a different ETS rate. In short, the analysis calculated the impact on exports and congestion rents when HOEP was $4.69/MWh higher, or $1.85/MWh lower.

5. Wind curtailment amounts were calculated based on the difference in actual wind output when HOEP was $5/MWh or below and forecasted wind output in those hours. The IESO does not currently provide hourly wind curtailment volumes and, as such, prices and forecasted volumes were used as a proxy to estimate curtailment amounts. Power Advisory's method likely understates curtailment to some degree. The IESO has stated that in 2021 there was 1,289 GWh of curtailed variable supply, including wind and solar. Power Advisory's method calculated 761 GWh of curtailed ***wind supply*** alone (we did not calculate solar curtailment). While wind curtailment is in many

ways a pricing phenomenon – wind assets will be curtailed when HOEP is below their marginal cost offer – curtailment can also occur for a number of localized grid-related reasons that will not be captured using our methodology.

6. Power Advisory's estimates on hydro curtailment rely on analyzing exports during different price spreads that align with the marginal cost of rate-regulated hydro facilities ($14.40/ MWh in this case). When the increase in price moves beyond the marginal cost of hydro, it is assumed that the difference in exports will be spilled by rate-regulated hydro generators, as they are no longer economic to export. In short, the increase (or decrease) in the ETS rate can result in hydro supply being uneconomic to export, while also being below marginal cost for dispatch – resulting in increased spill volumes.

7. The market price impact calculates the difference in total exports based on an increase in the ETS rate. It then uses the difference to calculate the reduction in market revenues that will ultimately flow to Ontario ratepayers through energy export revenues.

**APPENDIX B. CV OF TRAVIS LUSNEY**


## Travis Lusney

Director, Power Systems

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**SUMMARY**


Mr. Lusney is a Professional Engineer (P.Eng) with over 15 years of experience working in both the commercial and regulated areas of the electricity sector. Mr. Lusney is a knowledgeable industry leader with a focus on electricity grid analysis, generation development, energy storage resources, market assessment, regulatory & policy analysis, and risk mitigation. Mr. Lusney is a former distribution and transmission planner with a deep expertise in power system planning and resource integration.

Mr. Lusney joined Power Advisory after a position as the Senior Business Analyst of Generation Procurement at the Ontario Power Authority, where he was responsible for management and development of the Feed-In Tariff program. Prior to joining Generation Procurement, Mr. Lusney worked as a Transmission Planner in Power System Planning at the Ontario Power Authority where he was actively involved in regional transmission planning, bulk system analysis and supporting system expansion procurements and regulatory procedures. Mr. Lusney also worked for Hydro Ottawa Limited as a Distribution Engineer responsible for reliability analysis, capital budget planning, power system planning, and project management. Mr. Lusney offers a unique understanding of the similarities, differences and interactions between different power system network components and economics.


### Professional History

Power Advisory LLC (2011-Current)
Ontario Power Authority (2008-2011)
Hydro Ottawa Limited (2006-2008)

### Education

Queen's University

MSc Electrical Engineering, 2007
BSc Electrical Engineering, 2004

## PROFESSIONAL EXPERIENCE

**Power System Planning**

- Led a jurisdictional survey on behalf of the Independent Electricity System Operator (IESO) on five core initiatives: bulk system planning process, regional planning and non-wires alternatives, customer reliability, end-of-life assets, and competitive transmission procurement. Jurisdictional survey included developing a detailed survey tool and performing over 50 interviews with represents from the around the world including all US Northeastern ISOs, CAISO, system operator and regulator in the UK, system operator, regulator and market operator in Australia, as well as multiple distribution and transmission facility operators. The lessons learned from the analysis were used as an input into a comprehensive overhaul of the IESO's planning methods.
- Representative for Non-Wires Solutions clients on the Regional Planning Process Advisory Group (RPPAG) at the Ontario Energy Board (OEB). The RPPAG is to review and provide recommendations for implementation of regional planning process changes identified by the IESO's regional planning process review report. In addition to RPPAG responsibilities, represented Non-Wires Solutions at various stakeholder engagement sessions on regional planning and bulk system planning in Ontario and Alberta.
- Prepared multiple power system outlook to determine future resource needs and potential investment opportunities for supply resources. Analysis included reviewed and commentary on resource adequacy, operability needs, transmission integration, customer reliability and broad regulatory framework. The power system outlook considered key areas of risk assessment, supply development scenarios, investment opportunities based on connection capability and project economics by supply type.
- Supported the analysis and drafting of expert evidence for arbitration between a vertically integrated utility and an independent power producer in Western Canada. The evidence included analysis of power system, treatment of energy output from generation resources, capability to export and import energy from neighbouring jurisdictions, and curtailment options for generation output.

- Acted as a witness in Hydro One's transmission rate filing, an Ontario transmitter, providing an assessment on transmission loss in regulation in other jurisdictions and how transmission losses are included in power system planning decisions, including how those losses are related to conservation and demand management initiatives.
- Expert witness in power system planning and solar generation development for litigation between international investment bank and large Canadian law firm. Reviewed evidence and prepared expert evidence in response to findings. Provided testimony to superior court of Ontario as expert witness.
- Provided strategic advice and power system analysis to generation development and energy storage resource clients on connection capability of proposed generation projects. Assisted clients in determining optimal project location and estimation of connection cost for different interconnection options. Review of Impact Assessments for multiple clients to assess project operations risks and potential future power system constraints. Estimated reliability of supply for load customers or deliverability for supply resources. Worked with clients to amend or adjust impact assessments to resolve or mitigate project risks.
- Consulting resource for a First Nation community to review and comment on a System Impact Assessment for a mining development nearby. Analysis focused on the impact to the community's reliability and determine potential options to resolve service quality concerns. Reviewed evidence filed by the mining developer and transmitter (i.e., Hydro One) to determine system constraints and potential options for removing or mitigating the constraint.
- Reviewed and prepared commentary for the 2020 New Brunswick Power Integrated Resource Plan (IRP). The review included preparing analysis for supply resource decisions, assessing the impact of a potential federal ghg equivalency agreement for continued operation of the Belledune coal-fired generation facility and other power system component analysis.
- Assisted in leading engagement with distributors, transmitters and system operators for variety of clients. Engagement included determining interconnection options, assessing connection risks and establishing timelines and milestones to support overall project development.
- Supported analysis for the Integrated Power System Plan (IPSP) dealing with bulk and regional system considerations, including reliability assessment. Developed regional integrated plans for constrained areas. Lead stakeholder consultation with local distribution companies, regulatory agencies, transmitters and local government officials to develop 10 to 20-year plans and activity coordination.

- 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.
- Advised and supported a major gas generation procurement for the Province of Ontario. Work included analysis of regional power system needs and constraints. Assisted in the development of evaluated criteria considerations.
- Developed procedures and policy for system connection assessment under the Feed-In Tariff program, in particular lead the development of the Transmission Availability Test (TAT) and Distribution Assessment Test (DAT) used to assess connection capability. Oversaw development of custom database to support the connection assessment process and coordination with over 80 local distribution companies. Managed staff for regional system analysis as part of the Feed-In Tariff program to determine connection capability for contract awards.
- Lead a study on Distributed Generation impacts and opportunities in the major urban centers as part of a long-term energy plan. Lead analysis on behalf of the Ontario Power Authority to determine the distribution generation potential in Central and Downtown Toronto along with the associated cost to develop the distributed generation resources. Worked closely with the local distribution companies, city officials and key stakeholders in understanding specific and general barriers and benefits.
- Developed capital work planning process for Asset Management department to ensure accountability and situation and issue identification. Lead the development of the capital budget and work plan for all distribution projects including a 25-year capacity plan for Distribution rate filing. Oversaw capital project tracking and reporting metrics to ensure accountability and transparency for senior management requirements.
- Managed reliability statistical reporting as part of regulatory requirements and senior executive requests. Involved in evolution of information gathering methods and worst feeder identification. Lead reliability engineer working closely with planning, design and construction personnel in identifying issues and resolution members. Chair of the asset management committee which oversaw the expectations of future capital sustainment work and associated risk levels.

- Involved in the development of the distribution and station asset management plan as key support for distribution Rate filing. Involvement included preparing financial analysis, reviewing rate-filing materials, presenting to senior executive teams and coordinating internal team analysis and responses.

**Strategic Investment and Risk Assessment**

- Lead the development of Ontario wholesale electricity price forecast for multiple clients. Clients were provided with a description of wholesale price formation in Ontario. The forecasts include a description of assumptions and methodology based on assessments of power system fundamentals, government policy and Ontario's regulatory framework. Performed sensitivity analysis and scenario assessment to support a wide variety of investment and risk assessments.
- Financial and technical due diligence for generation and energy storage resource acquisition/sales. Due diligence includes detailed electricity market assessment, multiple scenarios of electricity price forecasts, analysis of input costs and risk factors for project economics. Provided summary and commentary on recent regulatory and policy activities that could impact project economics. Prepared financial models for different project arrangements and capital structures, performed sensitivity analysis and stress-testing results for clients. Hosted meetings with clients to respond to feedback and questions and ensure client understands risks and opportunities.
- Prepared analysis and opportunities for siting of new resources over multiple jurisdictions with focus on Ontario and Alberta. Analysis reviewed and assessed regional system plans and bulk system plans. Report to clients identified priority locations for developing new resources (e.g., energy storage, renewables, and gas-fired generation) based on technical, community and market price factors. Clients includes asset owners, financial entities, and technology providers.

- Strategic guidance for investments in energy storage solutions in Ontario. Advice included detailed summary of Ontario's electricity market and assessment of opportunities for energy storage solutions along with identification of primary risks to potential revenue streams. Calculated value stacking opportunities and discounts for providing multiple electricity services from a single energy storage resource. Provide an overview and assessment of regulatory and policy structure impacting energy storage resources. Clients for this service included project developers, technology providers, load customers, financial investors, and insurance companies. Energy storage technology types included battery-based, compressed air, pumped hydro, flywheel, novel technologies and thermal energy storage.
- Primary consulting resource for New Jersey Resources (NJR) in preparing responses and analysis for the community solar initiative in New Jersey. Lead discussion and analysis with senior leadership team including researching activities in other jurisdictions, potential marketing cost impacts and commentary on potential community solar program procedure requirements. In addition, prepared multiple energy storage use case analysis for NJR existing and future assets.
- For multiple clients provide market monitoring services for jurisdictions across Canada. Market monitoring includes following and analyzing electricity market developments, policy initiatives and regulatory activities. Prepared regular agendas and analysis for clients customized for their specific business and needs. Lead discussion and completed action items following meets to assist customers in maintaining and enhancing their business.
- Led the creation of a GHG marginal emissions factor analysis and tool to estimate the potential GHG emissions reduction potential for distributed combined heat-and-power (DCHP) applications in Ontario. Analysis included detailed assessment of Ontario power system outlook and calculations of marginal emission factor based on electricity market operations and supply. Prepared a model to assess the GHG emissions saving potential for different DCHP applications.
- Led the completion of an energy storage market assessment across select US jurisdictions. The report included a summary of existing and potential regulatory and policy structures for energy storage in each jurisdiction. Prepared a financial model for each jurisdiction and compared return expectations for different energy storage applications. Provided a summary of energy storage projects in service or under development within each market.

- Prepared and hosted strategy and information session for a district energy corporation. The workshop focused on the Ontario electricity market, participation of district energy, regulatory framework and market design changes, and future outlook. Attendance was from multiple departments including finance, regulatory, business development, operations and legal. Subsequently hired to provide wholesale price forecast in support of ongoing strategy support
- Lead the assessment of connection capability of renewable generation for the City of Swift Current and their local distribution company Swift Current Light & Power (SCLP). Estimate the future cost of renewable generation for comparison to future SaskPower wholesale electricity rates. In addition, SCLP requested an outlook on the battery-based energy storage system (BESS) market and the potential for deployment of BESS to support the integration of renewable generation within their distribution system. The assessment concluded that both solar generation and wind generation were viable options for SCLP.
- Building on the feasibility assessment, assessed the capability of the SCLP distribution system to become self-sufficient using a combination of renewable generation and other resources. Self-sufficiency for the purpose of the assessment was the ability to supply all electricity consumptions needs of the SCLP system on an hourly basis. SCLP would remain connected to the SaskPower transmission system and therefore receive power quality and reliability services from SaskPower. Power Advisory assessed two self-sufficiency scenarios to determine the appropriate mix of wind and solar generation installed capacity. The No Export Scenario assumes no excess energy will be delivered to the SaskPower transmission system. The 60% Back-feed Scenario assumed a reasonable amount of excess energy could be exported in any given hour (the amount of export capability was the technical back-feed limit determined in the feasibility assessment report).
- Review, analysis and commentary on regulated and unregulated of comparable LDCs for a large Ontario distributor. Analysis included detailed modeling of capital spending patterns of multiple LDCs and assessment of differences between spending focus and system plans.
- Advising generation developers on new competitive procurement processes and determining strategy to help ensure successful participation while reduce exposure to risk. Participated in consultation and stakeholder engagement as an expert in transmission planning, procurement design, and proposal bid development.

- Provided detailed analysis of operating gas-fired generation facilities as part of potential asset sale. Analysis included modeling financial returns, assessment of operational risks. Provided a summary of technical requirements and opportunities the facilities could provide the power system currently and in the future.
- Working with renewable energy developers (mainly wind and solar PV) to plan, construct and successfully reach commercial operation for projects with long-term. Work includes assessment of project risk, investment opportunities, development strategy, solutions for connection issues and advice for securing construction approvals and permits.
- Completed due diligence on project economics, connection capability and estimated generation operating performance for wide range of generation types as part of strategic acquisitions. Services included analysis of natural gas delivery, operation restrictions and government policy drivers.
- Analyzed the Long-Term Transmission Plan (LTP) for Alberta and developed a comprehensive forecast of Capital Expenditures over the planning time period (2014-2032). The forecast includes an estimate of Development Capital Expenditures by project and region over the three time periods considered in the LTP. Estimated Capital Expenditures for General Plant and Sustainment based on the growth expectations of Alberta's transmission rate base. The analysis provides a detailed view of the long-term trend for capital investment in Alberta's transmission system and includes an alternative scenario for lower economic growth and oil sand development.
- Working with manufacturers of solar PV and wind generation components regarding strategic advice and solutions to meet Provincial content requirements and ultimately increase their market share.
- Constructed a quantitative project attrition model for projects with FIT PPAs to determine opportunities for future investment for clients. The model determined probabilistically which contracted FIT projects were at risk of failing to reach commercial operation and identify where new connection capacity would become available.

**Supply Resource Procurement and Contracting**

- Retained by the City of Edmonton to assist in assessing the options to purchase green electricity (i.e., electricity from sources that do not emit carbon dioxide). Scope of work involved analyzing renewable electricity technologies and contracting options available to the City. Specifically, the City is interested in: assessing the cost of wind, solar, and biomass (biogas and landfill gas) technologies; determining the supply need and renewable generation resource potential to meet the 100% green electricity objective; and an overview of contracting models and summary of potential risks for the City
- Part of the Procurement Administrator for the Marine Renewable energy procurement to secure novel tidal resources in the Bay of Fundy. Supported engagement with perspective proponents and discussions with government agencies. Prepared request for proposal documents and power purchase agreement terms.
- Retained by Alberta Climate Change Office (ACCO) to prepare detailed design recommendations for a community generation program. The recommendations included eligibility requirements for proposed projects and evaluated price methodology to stack proposals in order of their relative value, with the ranking within the stack used to award contracts to successful applicants. Proposed contract provisions, payment structure and an outline of responsibilities for successful applicants in developing, constructing, operating and maintaining a community generation facility.
- Acted as the Independent Administrator for the Atlantic Link Solicitation. The solicitation process was initiated for energy to be bundled with transmission capacity on Emera Inc.'s proposed Atlantic Link submarine electricity transmission project for the delivery of clean energy into the ISO-New England market. As the Independent Administrator, provided assurance to proponents and the Federal Energy Regulatory Commission (FERC) as to the fairness and transparency of activities related to the Atlantic Link energy solicitation.
- Technical expert for the Alberta Infrastructure (AI) solar RFP. Provided analysis and strategic guidance on program design, commercial agreement provisions and stakeholder engagement. Assisted the evaluation team in the review and assessment of proposals submitted to the RFP including evaluation of technical requirements for participation and assisting in evaluated cost bid price assessment.

- Provide to select clients detailed competitor assessment for clean energy procurements including relative cost of capital analysis, capital cost estimates, procurement strategy, contract risk assessment, bid preparation and quality review of submissions.
- Prepared a framework for a unique demand response program for a district energy system. The program design included key qualifications for customers, methodology for calculating incentive structure, program administration requirements and presented draft terms for demand response service agreement.
- Technical expert for procurement participation for a variety of resource developers including renewables and energy storage. Provided detailed analysis and assessment of procurement process and documentation including strategy for development of proposed projects to maximize opportunities within the Request For Proposal (RFP) and Contract in the multiple procurement processes.
- Worked as the Renewable Electricity Administrator in Nova Scotia responsible for the developing and administrating a Request for Proposal (RFP) process to procure over 300 GWh of low impact renewable energy. The process included engagement with stakeholders, development of an RFP document and Power Purchase Agreement and filing the Power Purchase Agreement for regulatory approval with the Nova Scotia Utility and Review Board On August 2nd 2012, after completing the evaluation of all 19 proposals that were submitted, the process successfully concluded with the execution of 355 GWh of contracted facilities.
- Provided support to Non-Utility Generators (NUGs) in negotiations with the Ontario Power Authority for extension of existing Power Purchase Agreement. Support included economic dispatch analysis, development of net revenue requirement pro formas to determine contract value, leading negotiation and providing strategic advice.

- Modeling procurement mechanics and Ontario system characteristics for renewable energy developers to establish a strategic direction for successfully securing power purchase agreements. This work included modeling connection capability within both the distribution and transmission system and assessing attrition risk of currently contracted and under development projects. Responsible for development and ongoing management of the standard offer Feed-In Tariff program for Renewable Energy. Involved with a wide range of stakeholders including project developers, manufactures, investors, regulatory agencies and Government. Analyzed ongoing project costs and market rates to update and maintain Feed-In Tariff price assumptions. This work included analysis of supply chain evolution, equipment providers capability and assessment of project economics.
- Involved in domestic content development within the Feed-In Tariff program as chair of the Domestic Content Working Group. Advised and clarified expectations for project developers and manufactures in understanding the domestic content requirements.

**Regulatory and Policy**

- Technical consulting resource for Ontario Sustainable Energy Association (OSEA) participation in multiple Ontario regulatory proceedings. Regulatory proceedings included Enbridge Integrated Resource Plan (IRP), Enbridge Multiple-Year Demand-Side Management (DSM) application, Enbridge Annual Supply Plan 2021, and Ontario Power Generation 2022-2026 Rate application. As technical consultant, reviewed materials, prepared analysis and questions for applicants, prepared submissions on behalf of OSEA and participated in technical conference on various subject matters.
- Supported many clients in the participation of stakeholder engagements for potential evolution of regulatory framework in multiple jurisdictions. Support included analyzing proposed design changes for electricity markets, regulatory structures, and legislation. Assisted clients in preparing for stakeholder meetings and submissions. Acted on client's behalf in stakeholder engagements and provided strategic advice to clients on how best to position feedback and alternatives where warranted.
- Supported Energy Storage Canada (ESC) Alberta working group in the Alberta Electric System Operator (AESO) Bulk & Regional Tariff Design with focus on energy storage resources. Attended stakeholder sessions, prepared commentary and submissions on behalf of working group and performed analysis of preferred and alternative rate designs.

- Involved in an energy storage valuation report for Energy Storage Canada. The report summarized and calculated the benefits energy storage resource deployment in Ontario could provide to customers both quantitatively and qualitatively. Lead the analysis of transmission & distribution system investment deferral and direct-to-customer benefits. Support analysis on wholesale market savings. Presented to leadership council, working group and general membership at Energy Storage Canada.
- Supported for a consortium of clients the analysis of substation cost allocation for potential cost sharing between distributed connected generation and load customers within a distribution network in Alberta in response to the AESO pursuit of sub-station fractioning. The AESO had proposed and received initial regulatory approval to seek cost recovery from distributed connected generation for use of existing connection assets to the Alberta transmission system. Researched cost and design differences between load customer and generation customer substation design, prepared approach with justification for cost allocation and presented to consortium and the AESO during stakeholder engagement sessions.
- Prepared a detailed submission on behalf of Energy Storage Canada (ESC) for the Alberta Utilities Commission (AUC) Distribution System Inquiry (DSI) Module One. Module One focuses on the impact of innovative and emerging technologies impact on distribution system design, operations, capital requirements and cost of providing services. In addition, Module One seeks to understand the opportunity for new market entry within the monopolistic franchise. Reviewed, researched and analyzed multiple jurisdictions and energy storage technology types to support drafting of the submission. Prepared a presentation for the Module One technical conference and participated in the technical conference on behalf of ESC.
- Drafted a discussion paper and presentation on co-location of energy storage resources with renewable generation resources. The discussion paper outlined the benefits and barriers for co-location projects, provided an overview of ongoing policy & regulatory activities, identified options to address barriers and provided near-term recommendations.
- Consulting resource for the Electricity Distributor Association (EDA) on the analysis and preparation of a best practices discussion paper for evolving the Ontario connection process for distributed energy resources. Engaged with EDA members and DER proponents to determine best practices, barriers and opportunities. Lead the drafting of the discussion paper, engagement with stakeholders for feedback and assisted in preparing presentation to board of directors.

- Supported research, consultation with Electricity Distributor Association (EDA) members and drafting of the report entitled *Power to Connect: A Roadmap to a Brighter Ontario*, which identified the challenges and barriers within the statutory framework, and proposed solutions, with respect to the transition of LDCs to "Fully Integrated Network Orchestrators". The report provided detailed analysis of Ontario's regulatory framework, market design, and organizational structure.
- For multiple clients provided strategic advice on evolution of electricity regulatory framework including electricity market design, legislation, regulation, system codes and approval processes. Clients include Canadian Solar Industrial Association, Canadian Wind Energy Association, Association of Power Producers of Ontario, Energy Storage Canada, Energy Storage Canada, Quality Urban Energy Solutions of Tomorrow (QUEST) and federal and provincial government agencies & ministries.
- Developed a discussion paper on the barriers to development of load-displacement energy storage applications in Ontario. The paper detailed the benefits of energy storage for customers and the power system as a whole. The paper described key barriers restricting the ability to adopt energy storage solutions and proposed multiple regulatory framework changes that would reduce or remove the barriers based on experience in other jurisdictions and reflecting the unique Ontario electricity market.
- Performed analysis of industrial rate design options in Ontario for Canadian Solar Industries Association (CanSIA) to determine the potential impact to net-metered solar generation and energy storage applications. Analysis modeled eight different rate design options over a ten-year forecast period. The avoided cost revenue from the industrial rates were then used in a financial model to assess the potential returns for each option.
- Review, analysis and drafting of responses on behalf of the Association of Power Producers of Ontario (APPrO) and Canadian Solar Industries Association (CanSIA) to the Ontario Energy Board (OEB) for Residential distribution rate design and Commercial & Industrial distribution rate design. The analysis included assessment of impact on customers and suppliers economics, review of rate design in other jurisdictions, and identification of appropriate rate design that benefits rate-payers and distributed energy resource suppliers.

- Primary consulting resource for CanSIA's Distributed Generation Task Force (DGTF). The DGTF objective included developing a customer-based generation model for solar generation after the conclusion of the Feed-In Tariff (FIT) program in Ontario (post-FIT solution), to identify transitional changes to the existing FIT program to support the post-FIT solution and to support solar market growth in the long-term. Responsible for jurisdictional review to identify best practices for customer based solar generation, technical and policy analysis to support the post-FIT solution and development of recommendation report and accompanying communication plan with key stakeholders.
- Co-leader of Solar Development Evolution Working Group which has participation and support from key solar PV project developers, EPC firms, asset operators and owners. The mandate of the working group was to develop policy for a long-term customer centric procurement approach for solar PV generation and identify priorities for transition of the existing FIT program.

**Selected Speaking Engagements**

- Energy Storage Canada 2020: Panelist – View from Alberta
- Engineering Insurance Conference (AEIC 2019): Speaker -Energy Storage: Game Changer
- Canadian Wind Energy Conference 2019: Speaker -Hybrid Wind Energy Project Opportunities in Canada
- Energy Storage Canada 2019: Panelist - Markets and Regulations - Frameworks on the Move
- Alberta Utilities Commission Distribution System Inquiry Module One Technical Conference: Speaker -Energy Storage Resources
- Energy Storage Canada 2018: Speaker – Behind-the-Meter Storage for Commercial and Industrial Applications
- Energy Storage Canada 2018: Keynote Speaker -How Market Reforms are Driving Energy Storage Opportunities, April 2018 (Toronto) and June 2018 (Calgary)
- CanWEA Spring Forum 2017: Panelist - What lies ahead in Ontario and Quebec the low demand future, April 2017
- APPrO Conference 2016: Panelist - The evolving connection assessment and planning process in Ontario, November 2016

- Canadian Energy Research Institute (CERI) 2016 Electricity Conference: Ontario – A Case Study of Retail Price Impacts, October 2016
- Solar Ontario 2016: Moderator for panel on Ontario Electricity Market Renewal Implications for Solar Generation, May 2016
- Clean Energy BC - BC Generate 2015: Panelist on Overview of Canadian Renewable Energy Markets, November 2015
- CanWEA 2015: Panel Member on Wind Generation Integration in Canadian Wholesale Electricity Markets, October 2015
- Solar Ontario 2015: Panel Member on Lessons Learned for the Large Renewable Procurement, May 2015
- Green Profit 2015: Plenary Panel Member on The Future is Now: The Economic Case for Renewables, March 2015
- CanSIA's Solar Canada 2014: Panel Member on Setting Precedents for the Future of Solar Distributed Generation Utility Programs, December 2014
- CanSIA's Solar Ontario 2014: Moderator on Balancing Supply: A look inside Ontario's Electricity System during Peak Demand on July 17, 2013, May 2014
- CanSIA's Solar Ontario 2013: Presenter and Moderator on Electricity Consumer Empowerment – Enabling Distributed Solar Power Generation, May 2013
- Ontario Feed-In Tariff Forum: Panel Member on Barriers to Connection Solar Projects at the Local Level, April 2012
- EUCI's 3rd Annual Conference on: Ontario's Feed-In Tariff, June 2011
- 4th International Conference on Integration of Renewable and Distributed Resources, Albuquerque, December 2010
- OSEA Community Power Conference, November 2010

**List of Expert Testimony**

- Ontario Energy Board, Hydro One Network Inc's Leave to Construct Application for Merivale to Albion Line Reconductoring, Transmission Loss Analysis and Capacity Expansions Analysis (March 2021)
- Ontario Energy Board, Hydro One Networks Inc's 2017/2018 Transmission Revenue Requirement & Rate Application (EB-2016-016), Transmission Loss Reduction Options (December 2016)
- Alberta Utilities Commission, Alberta Electric System Operator's 2014 General Tariff Application (Proceeding 2718), Proposed Approach for Designating Transmission Projects (February 2014)

**APPENDIX C. CV OF BRADY YAUCH**


## Brady Yauch

Manager Markets and Regulatory

**Power Advisory LLC**

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## SUMMARY


An electricity market analyst and economist with 11 years of experience in energy market analysis and regulatory affairs. Focuses on in-depth analysis of the competitiveness and economic efficiency of wholesale energy markets and regulated utilities. Has appeared many times before the Ontario Energy Board, spoken at conferences and been published in media outlets across North America.


### Professional History

Market Assessment Unit (MAU) IESO
*Executive Director and Economist – Consumer Policy Institute (see below)*

### Education

York University, Masters Economics, 2012
University of Edinburgh, Masters, Cultural Politics, 2005

## PROFESSIONAL EXPERIENCE

### Market Competitiveness and Economic Efficiency

- Oversee Power Advisory's electricity price forecasts for Ontario and Alberta – providing many custom forecasts for energy facilities across the province and revenue forecasts after the expiration of PPAs for a number of market participants.
- Provided expert evidence as part of a Tax Court proceeding on the cost allocation and bill design of Ontario's electricity sector.

- Provided expert evidence as part of a private arbitration regarding energy retailers in Ontario and the current design of the province's wholesale electricity market. As part of the evidence, I provided testimony before the arbitrator.
- Was retained by NYSERDA to develop a methodology for understanding the risk of future Locational Marginal Prices (LMPs) on contracts for various renewable assets. The methodology was ultimately incorporated into NYSERDA's business planning.
- Provided an analysis and white paper for the Nuclear Innovation Institute (NII) on the role of energy storage and baseload nuclear generations in Ontario.
- Was retained by a client to create a dispatch model for New Brunswick and 10-year marginal price forecast.
- Was retained by multiple clients to undertake due diligence on various generation assets in Ontario.
- For CANREA, modelled the impact of increasing rooftop solar penetration in Ontario on wholesale prices, capacity prices and transmission constraints. The report was shared with policymakers and various public outreach organizations.
- Led the modelling and drafting of a report on the future of gas-fired generation in Ontario for the Ontario Energy Association (OEA).
- Was retained by a client to provided a ten-year model for integrating energy storage into Saskatchewan's energy grid. The model replicated dispatch and energy pricing across the vertical utility's electricity grid.
- Modelled the impact of renewable capacity and transmission in NYISO.
- Oversaw the modelling for Ontario's move to Locational Marginal Prices (LMPs), Enhanced Unit Commitment and a Day-Ahead Market (DAM) for a consortium of gas-fired generators. As part of the engagement, the analysis was used in negotiations to contract updates to ensure the incentive structure aligns with future market design.
- Led a jurisdictional review of Pumped Generation Storage (PGS) facilities in the New York and New England wholesale markets. Reviewed market rules and dispatch efficiency of PGS facilities.

- Reviewed the financial implications of moving to LMPs in Ontario for multiple market participants. Led the drafting of memos, analysis and settlement models.
- Designed a settlement model for hydroelectric facilities in Ontario moving to LMPs
- Designed a wholesale market model for Energy Storage Canada to determine the economic benefits of increased energy storage in Ontario. Led the drafting of subsequent report.
- Worked in the Market Assessment Unit (MAU) of the Independent Electricity System Operator, which undertook analysis for the Market Surveillance Panel (MSP).
- As part of that work, provided an assessment on the economic efficiency of the offer behavior of hydroelectric plants in Ontario in response to a regulator-imposed incentive mechanism. Reviewed the efficiency of transmission rights payouts and recommended a market rule change.
- Provided a detailed review of the competitiveness and economic efficiency of Ontario's wholesale market.
- Reviewed a cost guarantee program for thermal generators and provided recommendations to improve its economic efficiency.
- Provided assistance in the MAU-led review of the Industrial Conservation Initiative in Ontario and contributed to the final report.
- Led the MAU's analysis and remarks regarding Ontario's Market Renewal Program (MRP).
- Provided public commentary on the IESO's Demand Response program and its effectiveness.
- Have provided multiple reports and opinion pieces on the economics of large-scale megaprojects across Canada.

**Regulatory Affairs**

- Assisted in the drafting of evidence before the Alberta Utilities Commission on the incentives of Performance Based Regulation (PBR).
- Led the drafting of numerous chapters of a rate application by a LDC (Grimsby Power) before the OEB.

- Led a study for the Government of Northwest Territories on interruptible rates and incremental revenues for utilities. As part of the project, modelled NWT's electricity grid and the impact of incremental load through electrification investments.
- Led the drafting of a report for the Ontario Energy Association on how programs designed to increase energy demand in Ontario.
- Designed a cost allocation model for an LNG plant in Northern Ontario based on the OEB's Cost Allocation Model (CAM).
- Participated in hearing regarding Enbridge Gas Distribution's proposed Renewable Natural Gas (RNG) Enabling Program and Geothermal Energy Service (GES) Program (EB-2017-0319). Led the drafting of interrogatories, cross examination and final argument.
- Participated in regulatory hearing to approve the merger of Enbridge Gas and Union Gas. Submitted evidence (jurisdictional review) in the proceeding (EB-2017-0306/07), as well as led the drafting of interrogatories, cross examination and final argument.
- Participated in a hearing in response to a motion from OPG to review its rate application decision (EB-2018-0085). Drafted the organization's submissions.
- Led an intervention in the proceeding for Hydro One's 2018 – 2022 distribution rates (EB-2017-0049).
- Drafted interrogatories and final argument for an intervenor in the OEB application by Union
- Gas for approval of its 2015 natural gas Demand Side Management (DSM) conservation programs (EB-2017-0323/0324).
- Participated as an intervenor and party to the settlement of Westario's application to the OEB to set its distribution rates in 2018 (EB-2017-0084)
- Participated in hearing for Hydro One Remote Communities 2018 revenue requirement and customer rates for the distribution and generation of electricity (EB-2017-0051). Led the settlement agreement and drafted all interrogatories for client.
- Drafted comments to the Ontario Energy Board modernization panel.
- Participated as an intervenor and party to the settlement of Union Gas' application for distribution, transmission and storage of natural gas rates (EB-2017-0087).

- Participated in a hearing to set Ontario Power Generation's 2017-2021 rates (EB-2016-0152).
- Drafted the final argument, interrogatories and led cross examination.
- Participated as in intervenor in the OEB hearing to set Hydro One's 2017-2018 transmission rates (EB-2016-0160). Drafted the final argument, interrogatories and led cross examination.
- Participated in hearing and settlement conference for the Independent Electricity System Operator's (IESO) 2017 fees application (EB-2017-0150)
- Participated in settlement conference for Enbridge's application to the OEB for the disposition of deferral and variance account balances (EB-2017-0102).
- Led intervention in the application from Five Nations Energy Inc. (FNEI) to the OEB to set its transmission rates for 2017-2020 (EB-2016-0231). Drafted the final argument, interrogatories and led cross examination.
- Participated in the community gas expansion hearing before the OEB (EB-2016-0004). Drafted the final argument, interrogatories and led cross examination.
- Participated in the hearing before the OEB regarding plans from Union and Enbridge to comply with the province's cap and trade program (EB-2016-0300).
- Participated as an intervenor and party to the settlement of Union Gas' application for distribution, transmission and storage of natural gas rates (EB-2016-0245).
- Participated in the hearing regarding Hydro One's application to the OEB to purchase Great Lakes Power Transmission (EB-2016-0050).
- Participated in the hearing and settlement conference in the IESO's application to the OEB to set its 2016 fees (EB-2015-0275).
- Participated in the hearing regarding Union and Enbridge's application for pre-approval of the cost consequences of a 15-year transportation contact (EB-2015-0166/EB-2015-0175). Drafted the final argument, interrogatories and led cross examination.
- Participated in the hearing to set Hydro One's 2015-2019 distribution rates (EB-2013-0416/EB-2015-0079). Transmission Facility Review and Pricing Proceeding Support

**Research and Publications**

*Academic*

- Ontario's Electricity Market Woes: How Did We Get Here and Where are We Going, Energy Regulation Quarterly, July 2020

*Op-eds*

- Another megaproject pushing public utilities to the brink, *The Telegram*, September 30, 2017
- Government's mega utility projects spell mega-ruin, *Financial Post*, September 26, 2017
- Megaprojects like Site C bankrupt power utilities, *Vancouver Sun*, September 18, 2017
- Ontario's conservation program another corporate welfare handout, *Financial Post*, August 3, 2017
- Ontario's public power failure redux, *QP Briefing*, June 22, 2017
- How Queen's Park broke Ontario's provincial electricity sector, *Financial Post*, April 12, 2017
- Looking to lower Ontario power rates? Start with Pickering, where $550 million will be wastefully spent, *Financial Post*, March 29, 2017
- No prizes for guessing who's really to blame for Hydro One's soaring rates, *Financial Post*, January 6, 2017
- This time is different: OPG says its megaproject not like the others, *Toronto Star*, October 11, 2016
- How Ontario's 1 per cent can do its share to reduce fuel poverty, *Financial Post*, August 16, 2016
- A new debt retirement charge for Ontario electricity customers, *Financial Post*, April 27, 2016
- Queen's Park the biggest winner with cap and trade, *Hamilton Spectator*, March 23, 2016
- Ontario electricity rates fastest rising in North America, *Toronto Sun*, March 2, 2016
- Queen's Park moves to silence dissent on electricity, *Toronto Star*, January 4, 2016
- Ratepayers on the hook for Hydro, *Winnipeg Free Press*, December 23, 2015

- The Hydro One sale's upsides, *Financial Post*, November 5, 2015
- Debt, subterfuge will cost B.C. Hydro ratepayers, *The Times Colonist*, October 24, 2015
- Privatization perks, *Financial Post*, September 22, 2015
- A $2.6-billion stimulus for Ontario, *Financial Post*, August 12, 2015
- Much needed reforms could focus on Hydro One employees' pensions, *Financial Post*, April 24, 2015
- Achtung, Ontario! Renewables are a money pit, *Financial Post*, August 12, 2014
- While Canadians endured hardships during recent storms, customers in UK got compensated, *Financial Post*, January 7, 2014
- Why China's renewables industry is headed for collapse, *Financial Post*, December 10, 2013

*Notable Media Appearances*

- The Agenda,
- CBC, "On the Money"
- Many other TV and radio appearances, including BNN and CBC radio

*Reports*

- Multiple Monitoring reports by the Ontario Market Surveillance Panel
- How Megaprojects Bankrupt Public Utilities and Leave Regulators in the Dark, 2017
- Power Exports at What Cost? 2016
- Getting Zapped: Ontario's Electricity Prices Increasing Faster Than Anywhere Else, 2016
- Gone Too Far: Soaring Hydro Bills Offset Conservation and Hurt Conservers Most, 2015
- Falls Flat: Comparing the TTC's Fare Policy to Other Transit Agencies, 2015
- Corporate Welfare Goes Green in Ontario, 2014
- Toronto's Suburban Relief Line. 2014

*Presentations*

- Presentation to the Standing Committee on Natural Resources in the House of Commons

- Market Monitor conference Austin Texas, 2029, Reviewing Ontario's Industrial Conservation Initiative
- Presentation to Northwind conference, 2018, How megaprojects bankrupt utilities.

**Work Experience**

*Manager – Markets and Regulatory, Power Advisory, March 2020 – Present*

- Collaborate on Power Advisory's market and regulatory work for clients across North American jurisdictions.
- Particular expertise on the interaction between rate regulation and wholesale markets.
- Lead on Power Advisory's custom electricity price forecasts for Ontario
- Provide detailed analysis and modelling for a range of market participants in Ontario and other wholesale markets
- *Senior Analyst* – Markets Assessment and Compliance Division (MACD), the Independent Electricity System Operator**,** September 2018 – February 2020
- Senior Analyst with the Market Assessment Unit (MAU) within Market Assessment and Compliance Division (MACD).
- Oversaw research and investigations in Ontario's electricity market for the Market Surveillance Panel (MSP).
- Wrote and performed research for semi-annual monitoring reports published by the MSP.
- Provided analysis and research in public forums – both internally to MACD and to external stakeholders.
- Gained an in-depth knowledge of both the Ontario wholesale electricity market and markets in other jurisdictions.

*Economist and Executive Director – Consumer Policy Institute, July 2013 – September 2018*

- Oversaw research activities for the Consumer Policy Institute.

- Was a consultant for regulatory hearings at the Ontario Energy Board (OEB), in which I reviewed and commented on evidence presented by public utilities. I have submitted multiple papers to the OEB on a range of topics, such as pension reform, revenue decoupling, natural gas expansion and distributor rate applications. I have cross examined many witnesses and executives regarding energy issues in Ontario.
- Have appeared numerous times on both television and radio to discuss energy and other economic topics. My research has been quoted extensively by experts, lawmakers and the media
- Write analysis reports and articles for media outlets. I have several recent opinion pieces published in national newspapers.
- Oversee the work of interns and other employees at Energy Probe Research Foundation.

*Online Reporter, Commentator and Editor – Business New Network, 2010 – 2013*

- Wrote and edited all content published on BNN.ca, with a particular focus on economic issues.
- Attended lockups for budgets and interest rate announcements and published breaking stories.
- Notable articles include: “Canada’s lost decade in manufacturing,” “The rise and fall of
- Canadian exporters” and “More Fed action likely, but will it work?”
- Managed the outlet’s website and came up with ideas for new columns and ways to present our content.
- Interviewed leading analysts, officials and other commentators on economic, political and business issues.

*Researcher and Policy Consultant – Energy Probe Research Foundation, April 2009 – December 2010*

- Performed economic, financial and political research on economic, policy and energy issues.
- In-house specialist on European carbon credit markets. I helped build and maintain the first, and only (at the time), online database of carbon credit projects. I was often called upon to explain the carbon credit market to reporters, other policy groups and policy makers.

- Engaged with policy makers through interviews and reports.

*Freelance Writer/Reporter – January 2009*

- Wrote articles for a variety of publications, including: *Washington Post, China Daily, BlogTO, Building.ca* and other trade magazines. Articles often provided commentary on major issues.
- Research involved searching through government databases, company reports, interviewing specialists and conducting other studies.

*Producer, Writer – Brookshire Media, Toronto ON, January 2008 – December 2008*

- Reported on and investigated financial markets -- including commodity markets, equity markets and currency markets.
- Wrote and edited articles on both financial markets and international politics.

*Editor – Corp Tax, Chicago, IL, September 2006 to February 2007*

- Wrote internal reports.

  Explained tax policies and forms to clients.

## APPENDIX D. FORM A EXPERT'S DUTY

**FORM A**

Proceeding: EB-2021-0243

ACKNOWLEDGMENT OF EXPERT'S DUTY

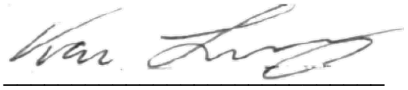
1. My name is Travis Lusney (*name)*. I live at Toronto (*city)*, in the Province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Association of Power Producers of Ontario (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date April 20, 2022



*Signature*

**FORM A**

Proceeding: EB-2021-0243

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Brady Yauch (*name*). I live at Toronto (*city*), in the province (*province/state*) of Ontario .

2. I have been engaged by or on behalf of Association of Power Producers of Ontario (APPrO (*name of party/parties)* to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.

3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
   (a) to provide opinion evidence that is fair, objective and non-partisan;
   (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
   (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.

4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date April 12, 2022

*Signature*