Evidence of Travis Lusney for:

Hawthorne to Merivale Reconductoring Project

EB-2020-0265

Prepared for:

Environmental Defence and Ontario Energy Board

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Submitted by:

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Table of Contents

INTRODUCTION

1. On December 2, 2020, Hydro One Networks Inc. (Hydro One) filed a Leave to Construct Application for the Hawthorne to Merivale Reconductoring Project (“Project” or “HMR Project”) with the Ontario Energy Board (OEB) under proceeding EB-2020-0265.

2. The project will reconductor the existing transmission circuits M30A and M31A spanning between Hawthorne Transmission station (“TS”) and Merivale TS in addition to related transmission station enabling work. The project is supported by power system planning analysis performed by the Independent Electricity System Operator (“IESO”). Based on the conclusions of the analysis, the IESO issued a letter to Hydro One requesting the transmitter to proceed with upgrading the identified transmission circuits.[1]

3. As part of the evidence in support of the project, Hydro One performed cost/benefit analysis of different options. The preferred option is referred to in the Hydro One Leave to Construct application as Alternative 3. Another option, Alternative 4, would reconductor the transmission circuits with larger conductors. Although Alternative 3 is now being put forward, the initial engineering and cost analysis completed by Hydro One for the IESO was based on Alternative 4.

4. Environmental Defence (“ED”) is an approved intervenor. Among other inquiries ED is seeking to assess whether it would be cost-effective, and ultimately lead to lower energy bills, for Hydro One to implement Alternative 4. In its February 3, 2021 letter requesting an opportunity to file evidence, ED indicated that these issues would be worthwhile to consider for this specific case and could also usefully shed light on Hydro One’s transmission loss valuation practices more generally,

5. ED has retained myself, Travis Lusney, Manager of Power Systems and Procurement at Power Advisory LLC to prepare evidence to “assess whether it would be cost-effective and ultimately lower energy bills for Hydro One to install a larger conductor, as outlined in alternative 4 in Hydro One’s evidence.” My curriculum vitae is attached.

6. This document represents my evidence for EB-2020-0265

[1] EB-2020-0265, Exhibit B-3-1

SUMMARY OF CONCLUSIONS

7. It is not possible with the information available to determine whether Alternative 3 or 4 is more cost-effective. Most importantly, the potential value of increased capacity provided by Alternative 4 has not been assessed but could be significant because the Hawthorne-to-Merivale path is a critical network component. Based on the avoided capacity cost estimates in the IESO's latest Annual Planning Outlook and the recent clearing price in the 2020 Capacity Auction, the ~~30~~ 122 MW of additional import capacity unlocked by Alternative 4 may be worth as much as $~~2.85~~11.6 million a year. The capacity value of increased import capacity or new capacity in Eastern Ontario could provide value both to the Ottawa region and provincial resource adequacy needs more generally. This would make Alternative 4 highly cost-effective.

8. In addition to the absence of an assessment of system and regional capacity described above, there are adaptations to Hydro One's valuation of transmission loss reductions that should be made. Without adaptation, transmission losses are greatly and inaccurately undervalued. Adaptations include:
    a. Loss reductions were valued based on the HOEP, which does not represent the true cost of electricity in Ontario's hybrid electricity market. This undervalues loss reductions by roughly 5 times based on analysis of energy flows on the existing transmission circuits in 2016, the highest historic loading year.
    b. The price of electricity was assumed to remain static. A forecast should be used that addresses best available information. The forecast should include existing and committed generation, carbon price costs and avoided energy costs to meet future unserved energy demand. Standard price forecasts can be used in the analysis to same time and effort.
    c. An explicit net present value calculation should be used based on a societal discount rate over the operating life of the asset. Hydro One is requesting ratepayers to commit to the asset for the entire operating life, the analysis should attempt to maximize the investment. It does not appear that an NPV analysis was used.

9. Despite this, I agree with Hydro One's ultimate conclusion that Alternative 4 is likely not cost-effective based on the value of the incremental transmission loss reduction benefits alone. However, given that the Hawthorne-to-Merivale path is a critical network path, regional and provincial capacity benefits may result in Alternative 4 being cost-effective; therefore, the capacity benefits should be quantified. Even if this value is determined to be a small fraction of the $~~2.85~~ 11.6 million mentioned above, it could still tip the scales to make Alternative 4 cost-effective. Furthermore, the valuation of loss reductions must be undertaken accurately to determine the overall cost-effectiveness of Alternative 4 including the value of the option of additional imports.

10. This report makes two recommendations.

a. First, the value of the increased capacity on the bulk network system should be assessed. The benefits could be as much as $~~2.85~~11.6 million per year, or $~~28.5~~116 million over the next decade. The opportunity to obtain them will be lost once reconductoring is complete.
b. Second, Hydro One's transmission loss valuation methodology should be updated to address the issues noted above.

BACKGROUND ON HMR PROJECT

11. The IESO letter issued to Hydro One states the Project need as follows:

> "In the past years, the M30/31A circuits have been operating near capacity at the time of summer peak supplying the peak demand of loads in the Ottawa area and carrying transfers from Ontario generating resources located in Eastern Ontario to the rest of the Ontario grid."[2]

12. In the letter, the IESO concluded that "*Considering the relatively low cost, technical feasibility and short implementation timelines, the conductor uprate option is the preferred solution for reinforcing the M30/31A circuits and increasing the capability of the HxM path*."[3]

13. Based on my review of the IESO's 2014 Interconnections report, I agree with the conclusions of the IESO that reconductoring of the HxM path is the preferred solution.

14. The HMR Project proposes to replace the existing single 230 kV 1843 kcmil aluminium conductor steel reinforced ("ACSR") with a duel-(i.e., two conductors) bundled 1443 kcmil ACSR 230 kV conductor (i.e., Alternative 3). In the Leave to Construct Application, Hydro One performed cost/benefit analysis on multiple transmission alternatives. Hydro One considered a variation of the HMR Project that would have replaced the existing single conductor with a larger duel-bundled conductor size of 1780 kcmil (i.e., Alternative 4).

15. Alternative 4 would increase the transfer capability (subject to station upgrades) and reduce transmission losses on the HxM path compared to Alternative 3. In the application, Hydro One concluded that the cost savings from reduced transmission losses over the life of the asset would exceed the incremental cost (~$4.5 million) of Alternative 4 versus Alternative 3 and therefore is not a cost-effective solution.

[2] EB-2020-0265, Exhibit B-3-1

[3] The IESO's Letter defines 'Hawthorne TS to Merivale TS' as the "HxM" path.

OBJECTIVE OF EVIDENCE

16. The objective of the evidence is to determine whether Alternative 3 or 4 is more cost effective while also shedding light on Hydro One's transmission loss valuation practices. The analysis by Hydro One indicates that both Alternative 3 and Alternative 4 are viable solutions (i.e., both would address the system need identified in the IESO Letter). To achieve this objective, the following analysis will be presented.

17. First, Hydro One has prepared historical analysis of transmission losses for the existing HxM path, Alternative 3, and Alternative 4. I have reviewed the transmission loss analysis and provide my view on the reasonableness of the results. The transmission loss analysis will be used to forecast future transmission losses for use in comparing Alternative 3 to Alternative 4.

18. Next, I will present an approach to determining the energy price used to value transmission losses. The energy price will be used to determine annual cost savings of Alternative 4 versus Alternative 3. The value of energy lost to transmission inefficiencies is important when determining if the additional investment on behalf of rate-payers is warranted.

19. Third, I will present a forecast of energy prices for valuing future transmission loss savings for Alternative 3 and Alternative 4. The forecast of energy prices will use the approach described above.

20. Next, I will outline a Net-Present Value (NPV) calculation to determine if the annual savings from reduced transmission losses is a net-savings or net-cost for Ontario ratepayers. A NPV calculation compares future savings from transmission loss reductions to the cost of investment all in present dollars (i.e., respects the future value of savings in the future). A positive NPV would indicate a net savings for ratepayers while a negative NPV would indicate a net cost for ratepayers.

21. In addition to the above analysis, I will assess the potential additional value of increased transfer capability of Alternative 4 versus Alternative 3 in meeting Ontario's future resource adequacy needs. In the IESO's 2020 Annual Planning Outlook, the IESO has indicated Ontario will have a summer and winter capacity deficit without the continued availability of existing resources in 2022.[4] Increased transfer capability on the HxM path could allow more Hydro Quebec imports to participate in the IESO's Capacity Auction.

[4] The IESO has announced that they are exploring a contract extension with Ontario Power Generation (OPG) for Lennox GS. If Lennox GS continues to operate the resource adequacy need is deferred to 2025.

REVIEW OF HYDRO ONE TRANSMISSION LOSS CALCULATIONS AND FORECAST OF FUTURE TRANSMISSION LOSSES

22. Transmission losses are a function of the current flowing and the resistence of a transmission circuit. The loss experienced in a conductor carrying alternating current is given by the equation I^2R, where I is the current and R is the resistence of that conductor. Current is clearly the more influential component of transmission loss analysis.

23. Historic transmission losses provide an understanding of how hourly power flow dynamics impact the value of investments to reduce losses. Through their Interrogatory Responses, Hydro One provided myself, in confidence, with detailed calculations of transmission system losses for the years of 2014 to 2020.[5] The calculations provided an estimation of transmission losses based on energy flows on the HxM path for the existing circuit, Alternative 3 and Alternative 4. The calculations also determined a max flow scenario based on scaling the 2016 flow to the maximum permissible flow on the line.

24. I have reviewed the transmission loss calculations and conclude they are an appropriate calculation of historic transmission losses for the three scenarios (i.e., existing, Alternative 3, and Alternative 4).

25. To assess the potential value of an investment to reduce transmission losses, a forecast of transmission losses is required. For this analysis, two scenarios were considered.

26. The first scenario is a conservative outlook where the 2016 transmission losses are increased annually based on demand forecast expectations. The IESO's 2020 APO provincial demand forecast Scenario 1 was used to increase power flows on the lines. The flows on the lines are capped at the maximum allowable permissible flows. The 2016 transmissions losses were used since they were the highest flows in data set made available by Hydro One. This scenario is referred to as the "Conservative Outlook"

27. The second scenario aligns with the sensitivity analysis performed by Hydro One and presented in their Interrogatory Response. The "Max Flow Outlook" assumes maximum annual permissible flow on the transmission circuits over the life of the asset.

28. The annual transmission loss savings for Alternative 4 versus Alternative 3 for both outlooks are shown in the figure on next page.

[5] EB-2020-0265-1-2-1 - ED Interrogatory #1

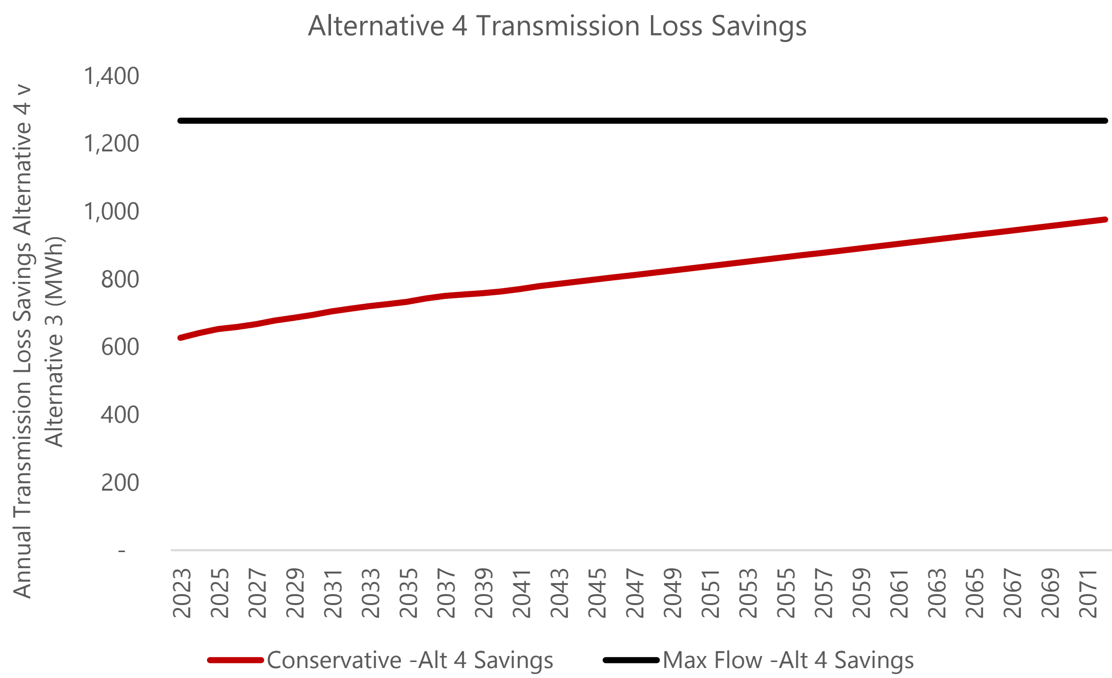

Figure 1: Forecast of Future Transmission Losses by Scenario

METHODOLOGY FOR ESTIMATING THE VALUE OF LOST ENERGY

29. Valuing transmission losses requires a price for the energy lost. Hydro One appears to primarily use a static Hourly Ontario Energy Price (HOEP) to determine that price.[6] This is inaccurate because it excludes the lion's share of the actual benefits of reducing losses. Instead, a forecast of the value of lost energy should be used, including HOEP, existing committed resources reflected in the Global Adjustment (GA) as well as future avoided cost of energy, as described below.

30. Previous debates on the appropriate energy value to use for transmission losses have included arguments that GA should not be included because it is a fixed cost. Reducing losses does not avoid payment of short term GA obligations. This may partially be true for market dynamics in Ontario but is not applicable when discussing transmission system inefficiencies. Losses are system inefficiencies; customers are essentially paying for energy production that is thrown away before delivery to a customer. The wasted payment for energy delivered to the grid should be reflected in system planning and expansions.

31. Ontario ratepayers are committed to pay for energy delivered at the price of HOEP + GA; the system should be designed to maximize the delivery of that energy as effectively as possible. Also, reducing losses will reduce generation costs in the future.

32. Similarly, it has been argued that GA should be ignored because it includes policy costs (e.g., renewable generation contracts and conservation). Regardless of the reason why commitments to payment for energy are included in wholesales prices, that is the value of electricity in the Ontario market. Excluding the GA would be to incorrectly assume that we will not continue to have to pay for these items. There is nothing to indicate that we will be paying less for energy in the future.

33. Finally, using only the HOEP is inconsistent with the cost-effectiveness test for conservation and demand measurement (CDM). The valuation of CDM has never been restricted to the avoided HOEP according to the IESO Energy Efficiency Cost-Effectiveness Guide.[7] In particular, the guide has always included avoided generation

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[6] This has been the historic Hydro One practice, but may be changing. In this case Hydro One added a sensitivity analysis including a $100 HOEP, but its main analysis and base case was still anchored by a $18 HOEP figure.

[7] https://www.ieso.ca/-/media/Files/IESO/Document-Library/conservation/EMV/2019/IESO-CDM-Cost-Effectiveness-Test-Guide.ashx

costs. Transmission loss reductions are simply another kind of conservation and should be evaluated in a consistent manner.

Components of Wholesale Electricity Prices in Ontario

34. In Ontario, wholesale energy prices are determined by two components. The first component is the Hourly Ontario Energy Price (HOEP), which is partially representative of the commodity portion of wholesale electricity prices. Due in part to Ontario's hybrid market structure, the market clearing price (which is reflected in the HOEP) does not reflect the entire wholesale electricity price. Practically all generation resources receive additional payments for their energy production. The additional payments are made through contracts from IESO or for rate-regulated generation assets owned by Ontario Power Generation. The additional payments to supply resources are collected from customers through the GA.

35. Over the past decade, the portion of wholesale electricity prices attributed to HOEP has fallen from ~50% in 2009 to roughly 15% in 2019 (see figure below). From 2015 to 2019, HOEP averaged 17% of wholesale electricity prices.

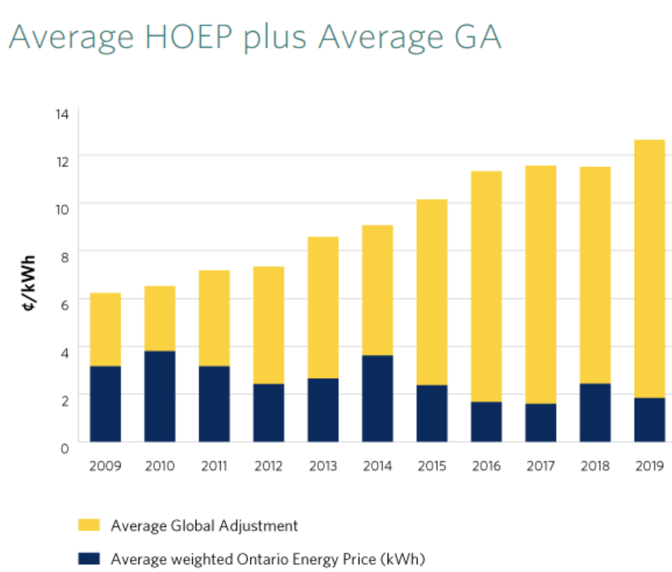

Figure 2: Average Wholesale Electricity Price: HOEP + GA[8]

[8] IESO - https://ieso.ca/-/media/Files/IESO/Power-Data/price-overview/Average-HOEP-plus-Average-GA.ashx

36. The value of transmission loss reductions is derived from the price paid to generation resources in Ontario. If no transmission losses existed in the electricity grid, the price paid to generators for injecting energy into the grid would also be the price paid by electricity consumers throughout the province. The existence of transmission losses means the volume of energy used to determine payment for energy injected by generators is higher than the volume of energy delivered to customers. In other words, transmission losses represent the volume of energy Ontario consumers have paid generators to inject into the grid but have lost to inefficiencies in the power system. The simple diagram below provides an illustrative example.

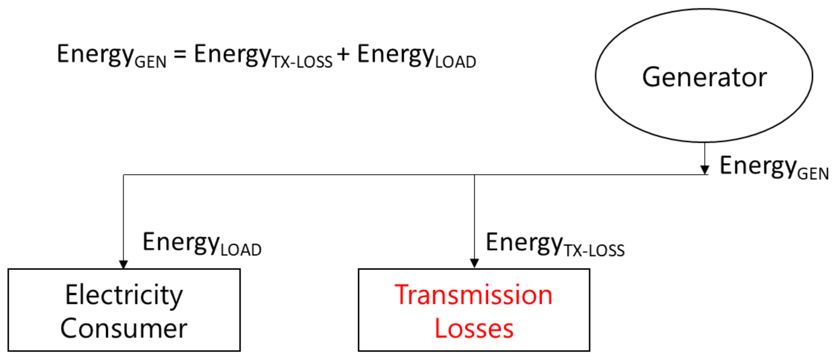

Figure 3: Illustrative Example of Transmission Losses

37. HOEP is an energy payment for all supply resources that inject energy into the Ontario electricity grid. Contract payments and rate-regulation funding generally take two forms: an energy payment for energy injected or a capacity payment for maintaining the participation of the generator in the Ontario electricity market. Typically, the energy payment under contracts or rate-regulation is through a Contract-For-Differences (CfD) structure where the amount paid to generators is the difference between the contract price and HOEP; thus, ensuring the generator receives the contract price regardless of variations in HOEP.

38. A vast majority of the generation resources in Ontario receive energy payments through their contract or rate-regulation arrangements. This includes all of Ontario's nuclear generation fleet, almost all hydroelectric facilities, all the non-hydro renewables (i.e., solar, wind and bioenergy) and some of the gas-fired generators. In total I estimate that roughly 90% of the annual energy production by supply resources in Ontario in 2020

receives a top-up payment in addition to HOEP for energy injected into the Ontario electricity grid.[9]

39. Put simply, transmission losses represent energy that has been paid for by ratepayers but is unusable due to system inefficiencies. For this reason, it is incorrect to only use HOEP when valuing transmission loss reductions for the purpose of comparing alternative solutions. A much more accurate alternative is to use the total cost of wholesale electricity (i.e., HOEP + GA) to determine the value of transmission loss reductions, including in relation to Alternatives 3 and 4.

Issues with Using Only HOEP

40. The behaviour of the HOEP during times of surplus baseload provides another illustration of why it is inaccurate to rely on the HOEP alone to value loss reductions. Due in part because of oversupply and top-up payments from contracts and rate-regulated assets, Ontario experiences significantly more negative-priced hours for HOEP then the market energy price in other jurisdictions. When looking at the HOEP alone, it appears as though generators are paying customers for the energy they produce and inject into the system. Contract & rate-regulation payments from the IESO create an offset such that generators are net-revenue-positive. More importantly, the top-up payments for generators are costs that ratepayers must fund even through the market price for electricity suggests ratepayers are being paid for energy.

41. Ontario has experienced many hours of Surplus Baseload Generation[10] that leads to negative HOEP, and the IESO expects Surplus Baseload Generation conditions to continue over the next 20 years.[11]

42. Using only HOEP in transmission loss analysis leads to inappropriate conclusions. Transmission losses for negative priced hours for HOEP would appear to be a net savings for customers even though energy is being lost in the transmission system. Further, when HOEP is $0/MWh the system would appear lossless even though energy is being lost throughout the system. This market dynamic significantly skews the assessment of

[9] https://www.ieso.ca/en/corporate-ieso/media/year-end-data

[10] Surplus Baseload Generation occurs when electricity production from baseload facilities (e.g., nuclear, hydro, wind, and solar) is greater than Ontario demand.

[11] See 2020 APO for forecast of Surplus Baseload Generation prepared by the IESO

transmission losses and does not reflect the actual cost of lost energy in the transmission system.

43. The year 2016, when the existing HxM path experienced the highest loading to date, is a good example of how skewed transmission loss analysis can be if only HOEP is used. The table below provides a summary of the negative priced hours (i.e., HOEP <$0/MWh), zero-dollar hours (i.e., HOEP = $0/MWh), and positive priced hours. In 2016 almost a quarter of all hours were negative or $0. That means a transmission loss assessment would view no cost for transmission losses in some hours or potentially a benefit of having transmission losses in the system. Viewing inefficiencies as a benefit to the power system for ~12% of the hours clearly shows the flaw of using HOEP only for transmission loss assessments.

Table 1: 2016 Hourly HOEP Summary[12]

2016 Hourly HOEP	Hours	% of Year
HOEP < $0 (Negative Priced Hours)	1,076	12%
HOEP = $0	920	10%
HOEP > $0	6,788	77%

44. The use of HOEP + GA significantly changes the amount of transmission loss saving potential for both Alternative 3 and Alternative 4 in 2016 if either investment had been in service compared to the existing circuits. The figure below shows loss savings in 2016 would be almost 5 times greater using HOEP+GA alone.

[12] IESO Data Directory

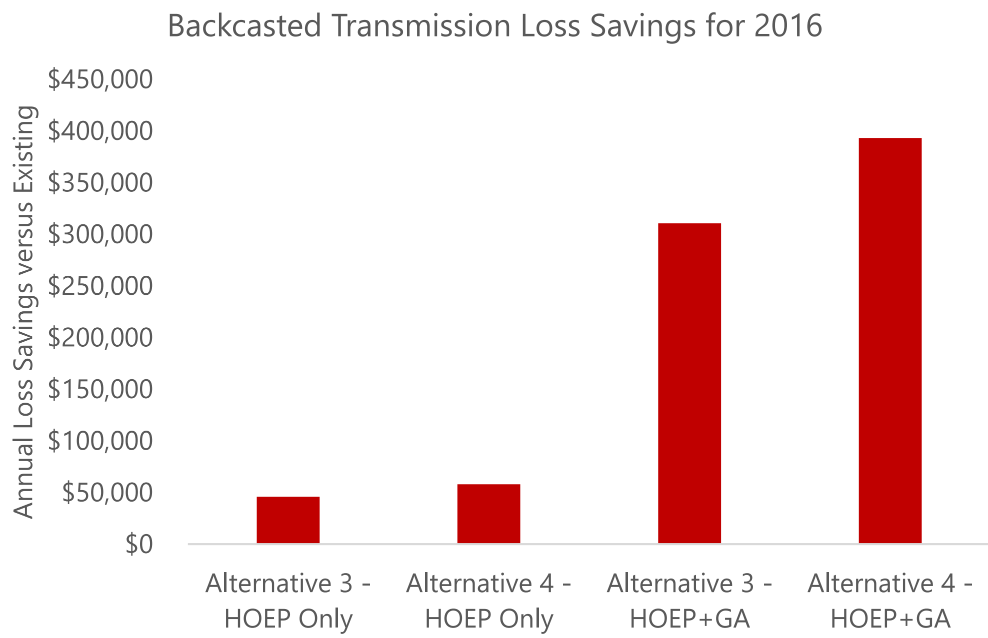

Figure 4: 2016 Transmission Loss Savings with only HOEP and with HOEP + GA

Replacing GA Over Time with Avoided Energy Costs

45. The contracted and rate-regulated assets that are funded by GA have a finite life with the majority expiring or retiring prior to the expected operating life of the reconductored transmission line. New or re-contracted resources will be required to replace energy injection. Lower transmission losses will mean less new energy required to supply Ontario electricity consumers. In addition to HOEP and existing GA commitments for existing supply resources, the value of transmission loss reductions includes future avoided cost of new energy.

46. Instead of using a static HOEP figure, the value of transmission loss reductions should be calculated based on a forecast of future energy costs. This should include components in the HOEP and the GA. There are any number of ways to derive these figures. I have chosen a method that can be done at any time based on the latest Annual Planning Outlook figure. However, there are other reasonable alternatives.

47. One of the key challenges is that the *committed* GA costs decline over time and it is unclear what cost will be paid for future contracted energy. To address this, I have used IESO avoided cost figures to forecast future HOEP + GA. The IESO published an estimate of avoided energy costs on an annual basis in their 2020 Annual Planning Outlook

(APO).[13] The avoided cost values are presented in 2020$, they have been converted into nominal values using an escalation rate of 2% for this analysis.

48. From a provincial power system perspective, I have assumed that the avoided cost values should be applied to potential unserved energy in future years. Unserved energy is the expectation of energy that cannot be supplied with the available committed supply mix. The avoided cost assessment by the IESO in the 2020 APO is the cost of new energy that must be procured to meet unserved energy.

49. Replacing committed GA costs as contracts expire & supply resources retire with avoided energy cost values ensures that the full value of transmission losses is calculated. Put another way, as GA decreases the avoided energy costs replace GA payments to fill future energy needs in Ontario. In the extreme when all generation resource commitments have expired and all energy is unserved energy (i.e., Ontario has no generation resources committed to serve Ontario electricity demand), future transmission losses would equal avoided energy costs.

[13] See Avoided Cost Data Module for 2020 APO - https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/APO-Avoided-Costs.ashx

FORECAST OF THE VALUE OF LOST ENERGY

50. To calculate the forecast of lost energy value, a weighted average price was calculated using the IESO's forecast of future annual demand and unserved energy in Scenario 1.

51. Power Advisory's proprietary HOEP + GA forecast was used for future wholesale electricity costs and weighted by served energy. The wholesale electricity prices reflect the impacts of the Comprehensive Electricity Plan (CEP) announced by the Ontario government in November 2020.[14] The price forecast includes carbon pricing and assumes all resource costs cease at the end of their contract term.

52. As resource costs are removed from GA, avoided energy costs are used to replace the energy value. My analysis assumes that only new energy is only secured for unserved energy in the future. The escalated avoided costs were weighted by unserved energy. The weighted average forecast price combines Power Advisory's HOEP + GA forecast and the avoided energy costs from the IESO.

53. The below table illustrates the difference between using just the HOEP and my recommended approach

Table 2: Comparison of Transmission Lost Energy Estimates

HMR Project Service Life	HOEP Only	Forecast Energy Cost
1	$18.62	$101.19
10	$18.62	$112.94
30	$18.62	$95.22
50	$18.62	$105.65

54. The use of a forecast need not be onerous. Although I developed a separate forecast for this case, Hydro One could use an off-the-shelf alternative or information from the IESO. Even simply using the existing HOEP + GA would be far more accurate than relying only on HOEP.

[14] The CEP was announced as part of the 2020 Ontario Budget

CALCULATION OF THE ENERGY VALUE OF TRANSMISSION LOSS SAVINGS

55. The annual weighted average value of transmission losses was calculated based on the methodology above and applied the two scenarios for future transmission losses on an annual basis. The transmission loss savings were forecast for the service life of the Alternative 4 investment, estimated to be 50 years.[15] The future transmission loss savings for Alternative 4 versus Alternative 3 for each scenario are shown in the figure below.

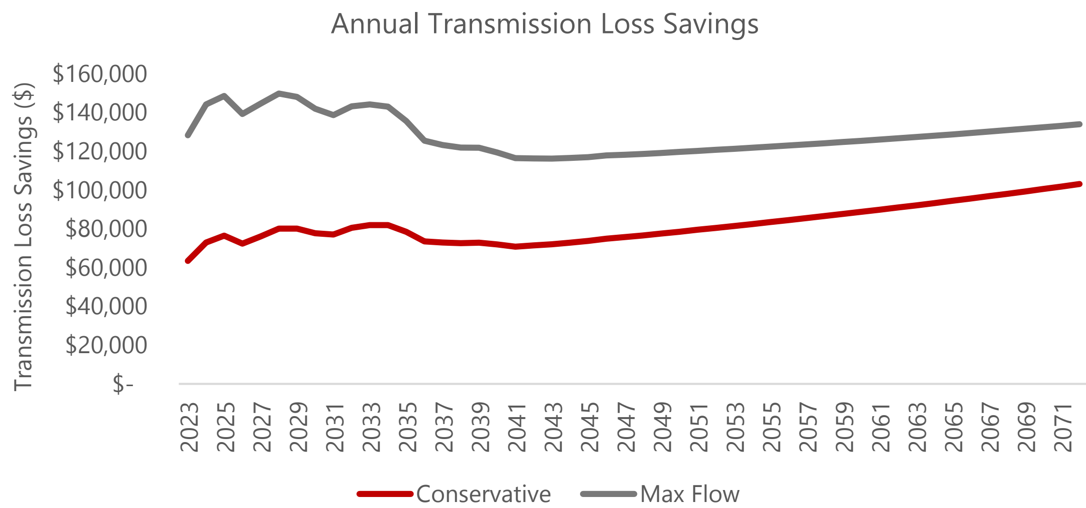

Figure 5: Annual Transmission Loss Savings

56. To calculate if the investment is a net savings or net cost to Ontario ratepayers, a NPV analysis is used. For the NPV analysis, a discount rate of 2% was used.[16] The initial investment is assumed to occur in 2022 of $4.5 million and future transmission loss benefits occur from 2023 until 2072 at the end of the operating life of the investment. The table below provides the results of the NPV analysis. Both scenarios appear to be a cost to ratepayers based on transmission loss analysis alone. However, the value of loss reductions is nevertheless significant and could in combination with other benefits make the Alternative cost-effective.

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[15] 50 years was chosen based on Hydro One's statement with respect to depreciation rate "Reflects 50 year average service life for towers, conductors, and station equipment, excluding land". EB-2020-0265-B-9-1 Table 2

[16] Justification for the discount rate was derived from: https://www.synapse-energy.com/sites/default/files/Final%20Report.pdf

Table 3: NPV Analysis for Transmission Lost Energy

	Average Annual Transmission Loss Savings	Net Present Value (2022-2072)
Conservative Scenario	$ 82,048	-$1,949,036
Max Flow Scenario	$ 128,443	-$413,804

VALUE OF INCREASED CAPACITY

57. In addition to lower transmission losses, Alternative 4 increases the transfer capability on the HxM path. In 2017, the IESO published a report "Ontario-Quebec Interconnection Capability: a technical review" that outlined the current import capability from Quebec as well as investments to increase the firm capacity. As part of the analysis, the IESO concluded that reconductoring the HxM path would allow the full capability of the High-Voltage Direct Current (HVDC) intertie with Quebec.

58. The higher transfer capability could allow Hydro Quebec to offer more capacity into the IESO's Capacity Auction to meet Ontario's resource adequacy needs. The difference in maximum transfer capability between Alternative 4 and Alternative 3 is estimated to be ~~~30 MW~~122 MW according to Hydro One (see table below).

Table 4: MW Ratings of M30A and M31A circuits[17]

MW Ratings	Today	Alt 3	Alt 4	Station as of Today	Station Uprated
Summer (35°C)	648	1102	1224	1080	1440
Shoulder (20°C)	698	1184	1318	1080	1440
Winter (10°C)	727	1235	1372	1080	1440

59. Using the APO avoided cost estimates for capacity (as opposed to energy used to determine the value of unserved energy), the ~~30~~122 MW additional capacity may be worth up to $~~3.6~~14.6 million a year (i.e., $10,000/MW-month x 12 months x 122~~30~~ MW).

60. The $~~3.6~~14.6 million a year value of avoided capacity cannot be attributed solely to Alternative 4 since payments must be made for the capacity import. The price of future import capacity is dependant on market fundamentals in Ontario and neighbouring jurisdictions, supply & demand balance expectations in neighbouring jurisdictions, transmission expansion costs, and other policy impacts (e.g., carbon pricing).

61. Results from the most recent Capacity Auction can be used for an initial assessment of the capacity value for Alternative 4. The Capacity Auction clearing price was $198/MW-day in the summer obligation period, roughly equal to $24,895/MW-year. Hydro

[17] EB-2020-0265 Exhibit I-2-8 -Table 1 in response to Environmental Defence Interrogatory #8

Quebec successfully cleared the auction with a quantity of 80 MW. If another ~~30~~ 122 MW can be offered by Hydro Quebec at that rate, the cost of capacity would be ~$~~750,000~~3M/year. This means that upwards of $~~2.85~~11.6 million in capacity value (i.e., $~~3.6~~14.6 million less $~~750,000~~3 million in capacity payments to Hydro Quebec) could be attributed to Alternative 4 for the additional capacity it unlocks in the Ottawa region and provincially for resource adequacy needs. In other words, Alternative 4 could potentially enable the purchase of capacity at a rate that is lower than what could be otherwise obtained.

62. There are many caveats that need to be considered when valuing future capacity. For example, Hydro Quebec may not offer the additional 122 MW capacity at the same price as the 80 MW that cleared in the Capacity Auction. Larger amounts of capacity may demand a higher price. Committing more capacity to Ontario means less capacity available to meet Hydro Quebec's own internal load. Capacity is not a fixed product, it is dependant on many conditions such as weather, economic growth, generation & transmission outages. Predicting when capacity is going to be needed is difficult and the price would reflect that uncertainty. Future capacity offers would also reasonably be priced by Hydro Quebec based on opportunity costs in other markets. As capacity need changes in neighbouring markets the cost of capacity could increase. In addition, there are internal Quebec transmission constraints that might limit the amount of firm capacity Hydro Quebec could deliver. All these caveats are under the control of Hydro Quebec and cannot be fully addressed without price discovery (i.e., future participation in the Capacity Auction or resource adequacy procurements) or contractual arrangements. The high-level analysis of the potential benefits detailed above is reasonanble but a more specific analysis would require the involvement of the IESO.

63. For Ontario, it is unclear if the additional transfer capability of Alternative 4 can be fully available or if there are other Ontario transmission system constraints that restrict the import capacity. In the 2020 Capacity Auction the IESO set a limit of 80 MW for imports; Alternative 4 (and Alternative 3 for that matter) may not allow the IESO to increase that limit. Further, there may be additional capacity within Eastern Ontario that could be unlocked by the increase in transfer capability from Alternative 4. I believe the IESO is best positioned to determine if the regional and provincial value can be unlocked.

64. If the capacity value can be unlocked, Alternative 4 would clearly be cost-effective. The $~~2.85~~11.6 million is potential benefits would pay for the $4.5 million investment within 2 years and ~~would likely cover~~could cover the additional station upgrades required in less than ~~5~~ 5 years (assuming station upgrades ~~noted by Hydro One do not exceed the initial $4.5 million investment~~are the $50 million estimated by Hydro One). The capacity value does not have to exist long-term to justify the Alternative 4 investment, it could ebb

away after some time and still support Alternative 4. For this reason, I recommend that the IESO assess the capacity value potential for Alternative 4.

CONCLUSION AND SUMMARY

65. This evidence has reviewed the transmission loss calculations by Hydro One and concluded that they are reasonable for the potential transmission loss savings of Alternative 4 versus Alternative 3. Two transmission loss savings scenarios have been developed for the operating life of the reconductored assets.

66. A value of transmission loss energy has been determined based on the weighted average wholesale electricity price (i.e. HOEP + GA) and avoided energy cost for served and unserved energy projections from the IESO respectively. This approach is much more reasonable than using HOEP as Hydro One did in their analysis. However, it is important to note that Hydro One's sensitivity analysis, which looked at HOEP at $100, is a step in the right direction. The approach of including the entire wholesale electricity price more accurately reflects the value of lost energy in Ontario's unique hybrid electricity market. Further, the value of future avoided energy costs reflects the continuing value of lower transmission losses to the Ontario power system.

67. A forecast of future wholesale electricity prices was developed and used to value lost transmission energy.

68. An NPV analysis was performed and concluded that Alternative 4 is likely to be a net cost to ratepayers if only transmission loss reductions are considered.

69. However, given that the Hawthorne-to-Merivale path is a critical network path, regional and provincial capacity benefits may result in Alternative 4 being cost-effective; therefore, the capacity benefits should be quantified. Even if this value is determined to be a small fraction of the $~~2.85~~11.6 million mentioned above, it would still tip the scales to make Alternative 4 cost-effective.

APPENDIX A: TRAVIS LUSNEY CURRICULUM VITAE

Travis Lusney

Power Advisory LLC

Travis Lusney

Manager, Procurement and Power Systems

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Professional History

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

Education

- Queen's University, MSc Electrical

Mr. Lusney is a Professional Engineer (P.Eng) with 14 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 generation development, energy storage resources, market assessment, regulatory & policy analysis, business strategy, 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 EXPERIENCE

Power System Planning

Lead 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.

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.

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.

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.

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.

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.

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.

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

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.

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.

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, Quality Urban Energy Solutions of Tomorrow (QUEST) and federal and provincial government agencies & ministries.

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.

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

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 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)

Hydro One Networks Inc.
EB-2020-0265
Leave to Construct: Hawthorne to Merivale

ACKNOWLEDGMENT OF EXPERT'S DUTY

1. My name is Travis Lusney. I live at Toronto, in the province of Ontario.

2. I have been engaged by or on behalf of Environmental Defence 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 March 9, 2021

Signature