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BY EMAIL AND RESS

October 29, 2021

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

Dear Ms. Long:

EB-2021-0107 – Hydro One Networks Inc. Leave to Construct Application – Ansonville TS and Kirkland Lake TS A8K/A9K Refurbishment Project – Interrogatory Responses

In accordance with Procedural Order 1 issued October 8, 2021, please find attached an electronic copy of responses provided by Hydro One Networks and the Independent Electricity System Operator to interrogatories posed in the aforementioned proceeding.

For ease of reference, below are the tab numbers for each intervenor:

Tab	Intervenor
1	Ontario Energy Board Staff
2	Environmental Defence
3	Pollution Probe

An electronic copy of these interrogatory responses have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

Joanne Richardson

cc. EB-2021-0107 Intervenors (Electronic only)

OEB INTERROGATORY #1

Reference:

Exhibit B, Tab 5, Schedule 1, pages 1 – 2

Preamble:

The reference describes two transmission alternatives considered. Hydro One states that the scope of work for Alternative 2 is "limited to refurbishing end of life structures, conductors and other transmission line components." Hydro One states that the higher LTE rating associated with Alternative 1 will be achieved "through the use of taller wood poles." Hydro One also states that Alternative 1 requires work on 180 circuit km and that Alternative 2 requires work on 112 circuit km. The per-circuit km cost of Alternative 1 is $423k, the per circuit km cost of Alternative 2 is $515k.

Interrogatory:

a) Please confirm whether the only major difference in the scope of work between Alternatives 1 and 2 is the use of taller poles in Alternative 1. If this is not the only major difference, please clarify.

b) Please clarify why Alternative 2 involves work on fewer circuit km than Alternative 1.

c) Please clarify why Alternative 2's cost per circuit km is higher if its scope of work is less than the scope of work of Alternative 1.

Response:

a) The major difference in the scope of work between alternatives is the length of the transmission line that requires structural upgrades/replacement (180 circuit-km vs 112 circuit-km). The majority of the work required for the preferred alternative, is due to ground clearance violations caused by change/decrease in conductor elevations (increased sag) triggered by higher maximum operating temperatures necessitated by the ampacity increase.

As Alternative 2 would keep the circuits at existing operating temperatures and ampacity, the sag and conductor elevations will not significantly change thus pole replacement to increase structure height due to ground clearance violations do not apply which reduces the distance of the circuit that requires work. The scope of work for Alternative 2 would be limited to replacement of assets at end-of-life condition.

b) Please refer to response a.

c) Economics of scale and efficiencies allow for the per km price to decrease when including additional circuit lengths in construction. While scope of work for Alternative 1 is larger, there are efficiencies for longer transmission lines that decrease project cost associated to the additional scope of work. In this case, cost associated to mobilization/demobilization, material yards, environmental assessments, engineering, consultations, and insulator/hardware replacement are very similar for the two alternatives. All these factors combined and divided by the increased line length resulted in a lower cost per km for Alternative 1.

OEB INTERROGATORY #2

Reference:

Exhibit B, Tab 5, Schedule 1, page 1

Preamble:

Hydro One states that Alternative 2 would result in an ampacity of 390 A, which would not meet a Long Term Emergency operating rating of 550 A.

Interrogatory:

a) Please comment on whether and how Hydro One considered transmission alternatives to Alternative 1 that would meet a Long Term Emergency operating rating of 550 A. If not, why not?

Response:

In addition to the Alternatives included in this application, the following two alternatives were considered during the initial development of this project:

Do nothing alternative: Circuits A8K and A9K are part of NERC's Bulk Electricity System and provide critical connection between Ansonville TS and Kirkland Lake TS. These transmission circuits were constructed in the 1930s and are in poor condition today, requiring renewal in order to maintain safe and reliable service. Continuing with the status quo will increase the risk of interruptions to numerous customers including H2O Power, Iroquois Falls Power Corp and local Hydro One distribution customers. Furthermore, not uprating these circuits to 550A will fail to meet the IESO's system needs in the area.

Build new replacement circuits: Building two new 90 km circuits to replace circuits A8K and A9K has a high level estimated cost of $140M, nearly double the cost of Alternative 1. This estimate does not include any potential costs required for additional real estate rights and forestry work. This alternative would also prevent the continued use of 249 existing structures that are used to complete the preferred Alternative and are not fully depreciated thus stranding assets. For completeness purposes, it is important to keep in mind that the proposed project is an otherwise sustainment project that aims to minimize structural modifications to achieve the ampacity request of the IESO.

OEB INTERROGATORY #3

Reference:
Exhibit B, Tab 3, Schedule 1, Attachment 2, page 2

Preamble:
The reference states that "the IESO understands that a rating of 550 Amperes is the highest rated conductor that can be accommodated with the current tower structures at the lowest incremental cost."

Interrogatory:

a) The IESO's recommendation to Hydro One to upgrade circuits ASK and A9K to 550 Amperes appears to have been informed by its understanding of the upgrade's lowest incremental cost. Did the IESO also consider higher rating options from the perspective of greatest benefit to ratepayers? If not, please comment on whether a more favourable balance of incremental costs and benefits (i.e., a greater net benefit) might be achieved for ratepayers from a solution having a rating higher than 550 Amps, recognizing that it might also involve greater incremental costs.

Response:
This response has been provided by the IESO.

a) The IESO's study focused on the most cost-effective way to reliably meet the demand in the area considering the end-of-life of circuits A8K/A9K.

   In developing the options for the replacement of circuits A8K/A9K, the IESO considered the rating associated with Hydro One's base sustainment plan (i.e., 390 Amperes), as well as the highest rating that can be achieved with the conductor selected as part of the base sustainment plan (i.e., 550 Amperes with the 411 ACSR conductor). Within this option set, the IESO determined that it is more cost-effective to reliably meet the demand in the area with a rating of 550 Amperes, the Upgrade Option, as compared to 390 Amperes, the Base Option.

The IESO did not consider higher incremental cost alternatives that would have exceeded the reliability need identified for the area in order to maximize net benefit overall for ratepayers. Doing so would have been outside the scope and timing of the sustainment project.

OEB INTERROGATORY #4

Reference:
Exhibit B, Tab 6, Schedule 1, Attachment 2, page 8, Table 5
Exhibit B, Tab 6. Schedule 1, Attachment 2, page 6, Table 3

Preamble:
The first reference states that "following the loss of circuit A9K, the companion circuit A8K would experience thermal overload starting in 2024 with the Upgrade Option; however, the resulting capacity gap is reduced when compared to that in the Base Option (refer to Table 5)."

The second reference states that "following the loss of circuit A9K, the companion circuit A8K will experience thermal overload starting in 2023, as soon as the line is in-service; this is represented as a capacity gap shown in Table 3 below."

Interrogatory:
a) Please clarify whether the capacity gap shown in Table 5 at the above reference represents a scenario with zero output from generation in the area. Otherwise, please clarify.

b) Please clarify whether the capacity gap shown in Table 3 at the above reference represents a scenario with zero output from generation in the area. Otherwise, please clarify.

Response:
This response has been provided by the IESO.

a) The capacity gap shown in the referenced Table 5 was calculated based on a scenario with zero output from local generation by Northland Power's natural-gas fired generation complex (NPKL CGS) in the area.

b) The capacity gap shown in the referenced Table 3 was calculated based on a scenario with zero output from local generation by NPKL CGS in the area.

OEB INTERROGATORY #5

Reference:

Exhibit B, Tab 6, Schedule 1, Attachment 2, page 9, Table 6

Preamble:

The reference illustrates that under a scenario where circuits A8K/A9K are upgraded to 550 Amperes, the Total Local Generation Support Required (49 MW – 120 MW) will, at times, exceed the Maximum Generation Support Provided by NPKL CGS G1-G5 (82 MW). The reference also states that no Other Generation Support will be required.

Interrogatory:

a) Please clarify why the reference suggests that no other generation support will be required when it also shows a seeming mismatch between total local generation support required and maximum support provided by NPKL CGS G1-G5.

b) Please confirm that that Total Local Generation Support Required 2024-2031 is more or less continuous in nature (e.g. relatively high capacity factor rather than peaking)

Response:

This response has been provided by the IESO.

a) There is an error in the Total Local Generation Support Required in the referenced Table 6. The corrected table is shown below, in which the Total Local Generation Support has been corrected to 52 MW – 68 MW, which is within the Maximum Generation Support Provided by NPKL CGS G1-G5 (82 MW), meaning that no other generation support is required under this option.

Table 6 - Local Generation Amounts to Meet Kirkland Lake Reliability Needs with A8K/A9K Upgraded to 550 Amperes

Total Local Generation Support Required 2024-2031 (MW)	Maximum Generation Support Provided by NPKL CGS G1-G5 (MW)	Other Generation Support Required (MW)
52-68	82	n/a

b) Confirmed. The Local Generation Support Required is continuous in nature. As noted in Exhibit B, Tab 6, Schedule 1, Attachment 2, page 5, Section 3.2, the customer mix in the Area is predominantly industrial with relatively flat load profiles and limited seasonal variation.

OEB INTERROGATORY #6

Reference:
Exhibit B, Tab 6, Schedule 1, Attachment 2, pages 7-8, Tables 3 and 5

Preamble:
Table 3 is titled "Kirkland Lake Reliability Needs with A8K/A9K Upgraded to 390 Amperes". Table 5 is titled "Kirkland Lake Reliability Needs with A8K/A9K Upgraded to 550 Amperes".

Interrogatory:

a) Please clarify whether the difference between the values in the two tables approximately represents the capacity increase from the proposed upgrade of circuits A8K/A9K to 550 Amperes? (eg. values in Table 5 minus values in Table 3 for the corresponding years). Otherwise, please explain and provide the approximate capacity increase of the proposed upgrade between 2023 and 2031.

b) What is the incremental cost of the Upgrade option (i.e. the proposed project) per unit of incremental capacity upgrade (i.e. relative to the 390 Amperes Base Option)? How does this compare to an indicative generation alternative or range of alternatives?

Response:
This response has been provided by the IESO.

a) The difference between the values in the referenced Tables 3 and 5, represents the additional MW that can be supplied to the local area through the A8K/A9K circuits when they are upgraded to 550 Amperes. If the circuits are not upgraded, these MW must be supplied locally.

b) Upgrading A8K/A9K to 550 Amperes enables approximately 52 MW of incremental power that can be supplied by the circuits, and with an assumed 70- year asset life. The incremental levelized cost per unit of incremental capacity upgrade is approximately $23,000/MW-year, but as the system is entering a period of sustained need, i.e., the system would be building capacity to support this local need, it is appropriate to include the levelized cost of new bulk system capacity backing the line before comparing to an indicative generation alternative. With the addition of this supply cost, the total cost of delivering the incremental capacity to the area would be approximately $152,000/MW-year. This is roughly half the cost of new local generation – approximately $312,000/MW-year – which is based on a small scale new build CCGT given the baseload energy requirement in the area; both figures are in 2020 dollars.

The difference in cost is due to both a difference in technology type (bulk system capacity is currently based on SCGT, a cheaper and more appropriate option to supply capacity to the broader system) and the size of the facilities that would be built (bulk system capacity would have a much larger installed capacity, and benefit from economies of scale).

OEB INTERROGATORY #7

Reference:

Exhibit B, Tab 6, Schedule 1, Attachment 2

Preamble:

The Upgrade Option (plus local generation support) was found to have a net benefit of approximately $451 Million versus the Base Option (plus local generation support).

Interrogatory:

a) Please confirm whether the estimated net benefit of $451 Million is a net present value for a period spanning 70 years. Otherwise, please clarify.

Response:

This response has been provided by the IESO.

a) The study considered a period from the in-service of the upgraded circuits in 2023 to 2092, a 70-year asset life. The estimated net benefit of $451 Million is a net present value (NPV) covering this period, but with an extra three years of discounting such that the result is a 2020 NPV.

OEB INTERROGATORY #8

Reference:

Exhibit B, Tab 6, Schedule 1, Attachment 2, page 9

Preamble:

The reference states that "the overall benefit of the Upgrade Option (plus local generation support) was found to be approximately $451 Million versus the Base Option (plus local generation support), which requires reliance of G6. This benefit increases to approximately $513 Million should new local CCGT be built to supplement the Area in place of G6 in the Base Option."

Interrogatory:

a) Please confirm that the major driver of the net benefit is reduced production from natural gas-fired generation because of increased A8K/A9K capacity. Otherwise, please clarify.

b) In the IESO's analysis, approximately how much less gas-fired production does the Upgrade Option (plus local generation support) cause?

c) Are natural gas prices an important variable in the estimated net benefit?

d) What natural gas prices were assumed and how robust is the estimated net benefit result to changes in those natural gas price assumptions?

e) If applicable, what are other major drivers of the estimated net benefit and what are their approximate respective contributions (aggregated as appropriate)?

Response:

This response has been provided by the IESO.

a) Confirmed. The major driver of the Upgrade Option net benefit is reduced production from local generation, and also reduced replacement local generation capacity following the expiry of the NPKL contracts.

b) The Upgrade Option reduces the local generation production requirement by approximately 455,520 MWh/year.

c) Both natural gas and carbon pricing are important variables in the estimated net benefit, as both dictate a large portion of the operating cost for the existing NPKL generation units and new local generation.

d) The natural gas price was assumed to be $3.74/MMBTU (Dawn hub, 2020 Canadian Dollars) in all study years, and was based on a price forecast by Sproule at the time of the study. If the natural gas price was to decrease by 25%, the estimated net benefit of the Upgrade Option would decrease by 16%.

e) Carbon price assumptions are another driver of the estimated net benefit, and were based on available information at the time of the study. The carbon price assumptions are as follows:
   - Federal Carbon Charge: $65/tCO2e in 2023 increasing linearly to $170/tCO2e in 2030, and held constant thereafter (all in nominal dollars)
   - Performance Threshold (existing generation): 370 tCO2e/GWh
   - Performance Threshold (new-build generation): 288 tCO2e/GWh in 2023 decreasing linearly to 0 tCO2e/GWh in 2030, and held constant thereafter

   If the Federal Carbon Charge forecast was to decrease by 25%, the estimated net benefit of the Upgrade Option would decrease by 18%.

OEB INTERROGATORY #9

Reference:

Exhibit B, Tab 6, Schedule 1, Attachment 2, page 9

Preamble:

The IESO's economic assessment assumed that "NPKL CGS units are replaced with local new-build CCGT following contract expiry."

Interrogatory:

a) Please confirm the approximate contract expiry date of the NPKL CGS units.

b) Please comment on whether the NPKL CGS Units have an end of life date and when that date is.

c) Please comment on approximately how the estimated net benefit would change under base and lower load growth scenarios if the NPKL CGS units were not assumed to be replaced with local new-build CCGT following contract expiry, but instead were assumed to continue to operate under whatever acquisition arrangement and reinvestment/upgrade scenario the IESO thinks might be reasonable.

d) Based on the response to question a) above, to what extent does the economic case for the proposed upgrade hinge on being compared against a new build CCGT following contract expiry of the NPKL CGS units?

Response:

This response has been provided by the IESO.

a) The contract for NPKL CGS – G1 to G5 expires on August 23, 2030. The contract for NPKL CGS – G6 expires on August 22, 2035.

b) NPKL CGS – G1 to G5 entered commercial operation in 1990 and will be 40 years old at the time of contract expiry. NPKL CGS – G6 entered commercial operation in 2004 and will be 31 years old at the time of contract expiry. The IESO cannot comment on projected maintenance regimes, nor Northland Power's intention to operate these units beyond contract expiry, that would inform an end-of-life date. Based on age, and for the purpose of the study, the IESO assumed that these units will not be available following contract expiry.

c) The estimated net benefit depends on the cost of local generation avoided by the incremental load meeting capability (LMC) of the Upgrade Option. The most punitive continued operation scenario to the estimated net benefit would therefore be if NPKL units were to participate in the energy market as merchant generation, for the duration of the study period, and without formal reacquisition (i.e., no NPKL facility capacity costs to be avoided by the Upgrade Option). Under this assumption, the estimated net benefit would decrease to $220 Million and $95 Million for reference load growth and lower load growth, respectively. The reason this assumption is overly punitive to lower load growth versus reference load growth hinges on how the Base Option changes, and again, what the Upgrade Option avoids. For lower load growth, the incremental LMC changes from avoiding 57 MW of new replacement local generation without the NPKL CGS units, to avoiding NPKL – G1 to G5 production without capacity costs. For reference load growth, the incremental LMC changes from avoiding 52 MW of new replacement local generation without the NPKL CGS units, to avoiding a blend of new local generation, NPKL CGS – G6 production without capacity costs and NPKL CGS – G1 to G5 production without capacity costs. Since the cost profile of what is being avoided under reference load growth is now higher than lower load growth (previously they were the same, both avoiding new local generation, but lower load growth with a greater incremental LMC), the estimated net benefit of the Upgrade Option is now higher for reference load growth, even though it has a lower incremental LMC.

d) Based on the analysis and the remaining estimated net benefit presented in c) above, the economic case for the proposed upgrade does not hinge on replacement decisions for the NPKL CGS units.

OEB INTERROGATORY #10

Reference:
Exhibit B, Tab 6, Schedule 1, Attachment 1, page 9

Preamble:
The IESO indicates that when carrying out the economic analysis of the two alternatives (Base Option and Upgrade Option), it is assumed that in both options the NPKL CGS units are replaced with local new-build CCGT following contract expiry. The IESO also explains that with respect to the Base Option, the IESO did a sensitivity analysis that assumed one scenario where unit G6 met the additional capacity required, and a second scenario where it was assumed that new generation was added to provide the additional capacity required, rather than relying on unit G6.

Interrogatory:
a) Please explain whether in the economic analysis of the Base Option where it is assumed that new generation was added rather than relying on unit G6, the scenario essentially assumed that the replacement of the NPKL CGS units was brought forward and at a larger capacity than required in the Upgrade Option, or whether a second, new generator was assumed. If a second, new generator was assumed, please discuss the cost impacts of instead assuming that the NPKL CGS replacement was advanced and expanded as needed.

Response:
This response has been provided by the IESO.

a) The Base Option requires that new local generation be built in 2028 and 2029 due to load growth in the area, and that replacement local generation be built once the respective NPKL CGS – G1 to G5 and NPKL CGS – G6 contracts expire. Prior to contract expiry and as early as 2025, NPKL CGS – G6 is expected to run baseload at its full capacity in the Base Option. As NPKL CGS – G6 is a SCGT, this is not an intended mode of operation given its high production cost and the resulting impact to asset life. Operating NPKL CGS – G6 in this manner would also eliminate the quick start and fast ramping flexibility that this unit provides to the system.

The Base Option sensitivity analysis described in the preamble evaluated the prospect of replacing NPKL CGS – G6's high production cost by advancing the new local generation intended to replace it once its contract expires. The sensitivity analysis determined that advancing the capacity and production costs of replacement local generation would not be economic when compared NPKL CGS – G6's high production cost. Note that since NPKL CGS – G6 is under contract, capacity costs associated with the facility within the contract period are considered sunk, and were not considered in the evaluation.

This outcome would also hold true if new local generation was advanced to replace NPKL CGS – G1 to G5 prior to contract expiry, and if advanced replacement of these facilities were to be evaluated under the Upgrade Option.

OEB INTERROGATORY #11

Reference:
Exhibit B, Tab 6, Schedule 1, Attachment 2, page 9

Preamble:
The IESO assessed the economic performance of the proposed upgrade against a lower load growth scenario.

Interrogatory:
a) Please clarify how much lower the load is in the low growth scenario compared to in the base case.

b) Please confirm that the upgrade option has a net benefit even under the lower load growth scenario. If confirmed, please comment on why this is the case. Otherwise, please clarify.

c) Please comment on whether the IESO feels that the overall result of net benefit even under lower load growth (i.e. the fact that there would be a net benefit, not the specific quantum of the net benefit) is robust or whether it is highly sensitive and could be easily reversed by changes to other key assumptions (including natural gas prices).

d) Why is the estimated net benefit of the proposed upgrade higher in the low growth scenario ($472 Million) compared to the base scenario ($451 Million)?

Response:
This response has been provided by the IESO.

a) The lower growth scenario considered demand from existing customers in the Kirkland Lake Area and their planned expansions, and excluded demand from new customers recognizing the inherent uncertainty in their development. The lower growth scenario compared to the reference forecast is shown in the table below.

Year	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Reference (MW)	120.2	136.7	140.7	195.7	203.7	203.7	205.7	207.7	211.7	211.7	211.7
Lower Growth (MW)	120.2	136.7	140.7	160.7	168.7	168.7	170.7	172.7	176.7	176.7	176.7

b) Confirmed. The estimated net benefit of the Upgrade Option under the lower growth scenario is $472 Million, which is higher than the estimated net benefit of $451 Million under the reference growth scenario. The reason is that local generation is required under all scenarios (i.e., NPKL CGS units and replacement local generation following contract expiry of the NPKL CGS units). Under the lower growth scenario and with the Upgrade Option, 57 MW of local generation can be avoided by cheaper bulk system capacity and energy; this is 5 MW more than can be avoided as compared to the reference scenario with the Upgrade Option. This is due to the change in power flows in the local area resulting from the lower load growth, which changes the transfer capability of the A x K circuits and ultimately allows for slightly more supply from the bulk system.

c) The IESO feels the estimated net benefit is robust under both load scenarios. The analysis provided in OEB Interrogatory 9c) and OEB Interrogatory 8d) and 8e) demonstrate the strength of the estimated net benefit if NPKL CGS replacement capacity costs are omitted, and if natural gas and carbon price assumptions are reduced.

d) Please see response to part b) above.

OEB INTERROGATORY #12

Reference:
Exhibit B, Tab 6, Schedule 1, Attachment 2, page 8
Exhibit C, Tab 1, Schedule 1, page 3
Exhibit B, Tab 3, Schedule 1, Attachment 2, page 2

Preamble:
The IESO states at the first reference that it understands that a conductor with a summer planning rating of 550 Amperes is the highest rated conductor that can be installed using the existing tower structures.

Hydro One states at the second reference that approximately 407 structures will need to be replaced to maintain adequate clearance and design loading and that, additionally, approximately 839 of the existing pole structures are in bad condition and considered end of life which will need to be replaced.

The third reference states that "the IESO understands that a rating of 550 Amperes is the highest rated conductor that can be accommodated with the current tower structures at the lowest incremental cost."

Interrogatory:

a) Please clarify whether the IESO's economic assessments account for the fact that the proposed Project will involve the replacement of approximately 1,200 structures (i.e. 407 + 839)?

b) What percentage of structures do the 407 + 839 structures represent? How many structures are not being replaced?

c) Please reconcile the fact that approximately 1,200 structures will be replaced as part of the project with the IESO's approach to limiting the size of the recommended option to what the existing tower structures can accommodate.

d) If the IESO knew that the project would involve replacing as many structures as it does, would it have considered larger capacity wires alternatives? If not, please clarify.

<u>Response:</u>

a) The IESO's economic assessment included the incremental capital costs of the Upgrade Option, which includes the incremental structure replacements required (i.e., 407 structures) in order to increase the summer planning rating of the circuits to 550 Amperes. The IESO's economic assessment does not include the capital costs of the 839 structures that are at end-of-life and subject to replacement in any case as they are common to both the Base and Upgrade Options and thus not incremental. .

b) b) Circuits A8K and A9K consist of 1,495 structures. 839 structures along the circuits are deteriorated and require replacement irrespective of the alternative pursued, i.e., sustainment or upgrade.

This project will replace an additional 407 structures of the remaining 656 structures in order to meet the clearance and design loading requirements to operate at the IESO requested Long Term Emergency rating of 550 A using Hydro One's smallest standard conductor, the 411 kcmil ACSR/TW. Thus 249 existing structures will accommodate the required increase in capacity without requiring replacement which drives the conclusion that it is the highest rated conductor that can be accommodated with the current tower structures at the lowest incremental cost.

c) Please refer to part a) above.

d) Please refer to part a) above.

OEB INTERROGATORY #13

Reference:
Exhibit B, Tab 1, Schedule 1, page 3

Preamble:
Hydro One states that the project will involve $6 Million of OM&A removal costs.

Interrogatory:
a) Please clarify what the $6 Million of removal costs will pay for and how the figure was estimated.

b) Please comment on how the $6 Million compares to the removal costs in other comparable projects.

Response:
a) The $6M will cover the cost associated with the removal of any asset that is no longer required/replaced. Based on historical data, the removal costs were estimated at 8% of the capital estimated amount which is inline with comparable Hydro One projects.

b) Please refer to part a.

OEB INTERROGATORY #14

Reference:

Exhibit B, Tab 9, Schedule 1, page 1

Preamble:

The reference states that the removal costs are $5.9 million consisting of a $5.5 million charge to the transmission network pool and a $0.4 million charge to the transmission line connection pool.

Interrogatory:

a) Please clarify if the $5.9 million of removal costs includes any credits for salvageable material including copper wire. If so, please specify the amount. Otherwise, please clarify how the salvage value of existing material is considered in Hydro One's project cost estimate.

Response:

a) While there are credits associated to the salvageable material, it is estimated that these credits will be offset by the cost of waste removals.

OEB INTERROGATORY #15

Reference:

Exhibit B, Tab 9, Schedule 1, page 1
Exhibit B, Tab 6. Schedule 1, Tables 1 to 8

Preamble:

The first reference states that "There are no incremental operating and maintenance costs as a result of the proposed project."

The second reference present the net present value, revenue requirements and pool rate impacts based on an annual incremental OM&A cost of $0 for 25 years.

Interrogatory:

a) Please explain how vegetation management has been factored into the project.

b) Will there be any vegetation managements costs incorporated into the initial capital cost of the project or recurring during the asset lifecycle?

c) Please clarify if there are any adjustments to the vegetation management cycle as result of the right-of-way clearing for the capital project? If so, have these been incorporated into the net present value calculations for the project?

Response:

a) There will not be any adjustments to the vegetation management cycle as a result of the clearing required to complete the Project as there will be no right-of-way modification or expansion.

b) Please refer to part a.

c) Please refer to part a.

OEB INTERROGATORY #16

Reference:
Exhibit B, Tab 7, Schedule 1, page 2
Exhibit B, Tab 7, Schedule 1, Table 1, page 1

Preamble:
The first reference above outlines project risks and states that the scope of the project on which the cost estimate in Hydro One's application is based corresponds to an AACE Class 3 (-20% / +30%).

The first reference states that "until a detailed line inspection and additional studies and surveys are completed, there is a risk of scope changes, including structural and foundation refurbishment resulting in increased cost and a delayed in-service date".

The second reference states the total project cost of $69.686 million, which includes a contingency cost estimate of $6.184 million. This contingency cost estimate represents approximately 10% of the pre-contingency project cost.

Interrogatory:
a) Please explain the methods Hydro One used to assess project risks for the Ansonville TS by Kirkland Lake TS A8K/A9K Refurbishment Project and please clarify how Hydro One's contingency estimate relates to that analysis and why the contingency estimate is appropriate. Please clarify whether Hydro One's contingency estimate is consistent with its AACE Class 3 project cost estimate.

b) Please describe how the contingency cost estimate for the Ansonville TS by Kirkland Lake TS A8K/A9K Refurbishment Project compares to contingency cost estimates developed for other comparable Hydro One projects.

c) How did Hydro One develop its estimates for project material, labour, equipment rental and contractor costs?

Response:

a) Hydro One utilizes the risk assessment framework from the Project Management Institute (PMI) “A Guide to the Project Management Body of Knowledge”, an industry standard. This framework was also used as guidance to determine the contingency using a quantitative risk analysis.

Hydro One’s Risk Management Process for the Project is described below:

- Risk identification: Risk types associated with environmental, external stakeholders, permits and approvals, engineering, subsurface conditions, construction, material delivery timelines, outages, and other external factors were determined. Each risk was provided a unique identifier, risk title, description and assigned a risk owner.
- Risk analysis: A probability (i.e. likelihood) of each risk occurrence is assigned to that risk, along with its impact on project schedule and cost. The probability of each risk was then multiplied by the impact to determine the expected value for each risk. The sum of all individual expected cost values represents the total contingency reserve for the Project of $6.2M.
- Risk response plan: Mitigation actions, action delegate, action date and risk expiry date were completed for each risk.

The contingency reserve amount that was determined from the risk assessment is an accepted practice in the industry and considered appropriate for this Project.

b) The contingency amount for the A8K/A9K Project is 10% of direct costs which is within the range of 5% to 15% of direct costs similar to other line construction projects recently undertaken by Hydro One. The contingency amount is calculated by project specific risk factors which are identified at a Hydro One conducted pre-construction kick-off Risk Workshop.

c) The A8K/A9K Project estimate was prepared using Hydro One’s current standard labour rates for the portion of the work that will be performed internally. Material, equipment rental and construction labour estimate was developed by Procurement & Construction contractor and reviewed by Hydro One based on experience garnered in past and ongoing construction projects for the categories listed above.

OEB INTERROGATORY #17

Reference:

Exhibit B, Tab 7, Schedule 1, page 4
Exhibit B, Tab 7, Schedule 1, page 3, Table 2

Preamble:

The first reference states that "the A8K circuit will be refurbished in its entirety and put in service before beginning work on the A9K circuit. This significantly reduces the line cost efficiencies that can be obtained on this parallel work since activities such as mobilization and stringing setup will double compared to a single setup approach required on comparator projects shown on table above."

Interrogatory:

a) Please comment on why the fact that work on A8K and A9K will be done in series rather than at the same time will impact the cost comparison of the Project to the comparators shown in Table 2 given that the comparison is made on a circuit km basis.

Response:

a) For comparable projects, there was flexibility to complete work along the transmission line under same outage windows. This same opportunity is not available for the A8K/A9K Project. Thus, the inability to work on the A9K circuit until A8K circuit is completed limits efficiency opportunities and impacts estimated project cost per km.

OEB INTERROGATORY #18

Reference:
Exhibit B, Tab 7, Schedule 1, page 3, Table 2

Preamble:
The bottom row of Table 2 inflates comparator project costs at 2% per year for 2023 Nominal Dollars

Interrogatory:
a) Please revise the bottom row of Table 2 using actual inflation rather than a 2% approximation.

Response:
It is unclear what specific inflation rate OEB Staff would like Hydro One to utilize to modify the comparator projects.

The 2% used in the prefiled evidence is consistent with the 2021 Inflation Parameters issued by the OEB on November 9, 2020 for inflationary adjustments in 2021 rate adjustment applications.

> *The OEB has calculated the 2021 inflation factor for electricity distributors to be 2.2%, and for electricity transmitters and OPG to be 2.0%.*

Hydro One is aware that the OEB has initiated a proceeding on its own motion to consider the values of the inflation factors to be used in rate adjustment applications for rates effective in 2022. The docket for that motion is EB-2021-0212.

Based on the information shared in Procedural Order 1 of the aforementioned proceeding, preliminary calculations of the inflation factors used for adjusting rates in Price Cap IR, Annual Index IR, Revenue Cap IR, and other approved rate adjustment applications for rates effective in 2022 are estimated to be 2.5%[1]. As of the date of this response, however, a final decision on this motion has not been issued by the OEB.

[1] EB-2021-0212 – Procedural Order 1 – August 27, 2021 – Page 1

Given the above, Hydro One does not anticipate a revision of the inflation factor is necessary for the purposes of this Application.

OEB INTERROGATORY #19

Reference:

Exhibit B, Tab 7, Schedule 1, page 3, Table 2

Preamble:

Table 2 summarizes the costs of comparable line projects.

Interrogatory:

a) Please clarify whether the comparable line projects involved structure replacements. If so, what proportion of the total cost of those projects did structure replacement represent?

b) Please estimate the proportion that structure replacement represents out of the total cost of the Ansonville by Kirkland Lake project.

Response:

a) Structure replacements represent 10% of project estimated capital cost for D2L and 18% project estimated capital for H9K.

b) Structure replacements represent 21% of project estimated capital cost.

OEB INTERROGATORY #20

Reference:

Exhibit E, Tab 1, Schedule 1, pages 2-3

Preamble:

Hydro One states that its proposed form agreements are similar to those previously approved by the OEB in previous Hydro One leave to construct application proceedings (such as EB-2019-0077 and EB-2018-0117).

Interrogatory:

a) Please advise whether there are any substantive differences between the previously approved form agreements referenced above and the form agreements that Hydro One requests approval of as part of the Ansonville TS by Kirkland Lake TS A8K/A9K Refurbishment Project and explain any such differences.

Response:

No, these documents do not have any substantive differences to those previously approved.

OEB INTERROGATORY #21

Reference:
Exhibit B, Tab 1, Schedule 1, page 2

Preamble:
Hydro One states that it will register easements on ten properties on the right of way that do not have easements registered on title.

Interrogatory:
a) Please confirm that the easements referenced above are permanent easements. Otherwise, please clarify.

b) Please provide a brief status update on Hydro One's progress towards obtaining the land agreements required for the Project.

Response:
a) Any easements Hydro One obtains on private property will be perpetual easements registered on title.

b) Hydro One has not received any concerns to date regarding the registration of any permanent easement rights. Given that the required right of way on these properties is no different than the existing right of way, Hydro One does not foresee any issue with finalizing the registered easements. In effect, the easements will remain the same but will be registered to provide clarity and definition of the right of way.

   Hydro One continues to anticipate finalizing any registration of permanent easement rights such that the Project Schedule provided at Exhibit B, Tab 11, Schedule 1 can be maintained.

OEB INTERROGATORY #22

Reference:
N/A

Preamble:
Hydro One has applied for leave to construct approval. Procedural Order No.1 includes the OEB's standard conditions of approval for transmission leave to construct applications. OEB staff proposes that the standard conditions be placed on Hydro One in relation to this application. The standard conditions are reproduced below for convenience:

1. Hydro One shall fulfill any requirements of the SIA and the CIA, and shall obtain all necessary approvals, permits, licences, certificates, agreements and rights required to construct, operate and maintain the project.

2. Unless otherwise ordered by the OEB, authorization for leave to construct shall terminate 12 months from the date of the Decision and Order, unless construction has commenced prior to that date.

3. Hydro One shall advise the OEB of any proposed material change in the project, including but not limited to changes in: the proposed route, construction schedule, necessary environmental assessment approvals, and all other approvals, permits, licences, certificates and rights required to construct the project.

4. Hydro One shall submit to the OEB written confirmation of the completion of the project construction. This written confirmation shall be provided within one month of the completion of construction.

5. Hydro One shall designate one of their employees as project manager who will be the point of contact for these conditions, and shall provide the employee's name and contact information to the OEB and to all affected landowners, and shall clearly post the project manager's contact information in a prominent place at the construction site.

Interrogatory:

a) Please comment on the above standard conditions in relation to this application. If Hydro One does not agree with any of the draft conditions of approval, please identify the specific conditions that Hydro One disagrees with and explain why. For conditions in respect of which Hydro One would like to recommend changes, please provide the proposed changes.

Response:

Hydro One has no concerns with the above standard conditions in relation to this Application.

ENVIRONMENTAL DEFENCE INTERROGATORY #1

Reference:
Exhibit B-5-1

Preamble:
"Hydro One aims to refurbish all deteriorated line sections of circuits A8K and A9K, while increasing each circuit's Long Term Emergency operating rating to 550 A, as requested by the IESO. To achieve this, the following options were considered:

> **Alternative 1 (Preferred) –** Replace the deteriorated components along all line sections of circuits A8K and A9K, including obsolete copper conductor, aluminum conductor steel reinforced ("ACSR") conductor tested to be at end-of-life condition, corroded steel shieldwire and rotten wood poles. The higher Long Term Emergency operating rating of 550 A will be achieved through the use of taller wood poles, which will provide for the increased clearances required for higher thermal capability. Any work on non-deteriorated components in order to meet the increased rating requirement will be minimized. Alternative 1 refurbishes an approximate total of 180 circuit km of transmission circuits A8K and A9K.

> **Alternative 2 –** Replace the deteriorated components along all line sections of circuits A8K and A9K, including obsolete copper conductor, aluminum conductor steel reinforced ("ACSR") conductor tested to be at end-of-life condition, corroded steel shieldwire and rotten wood poles. The existing ampacity of circuits A8K and A9K are limited to 230 A and 290 A respectively. Scope of work for this alternative is limited to refurbishing end of life structures, conductors and other transmission line components. This approach would result in an ampacity of 390 A. This alternative, however, would only meet the pure sustainment need and would not meet a Long Term Emergency operating rating of 550 A, as requested by the IESO. Alternative 2 refurbishes an approximate total of 112 circuit km of transmission circuits A8K and A9K."

Interrogatory:

a) Please confirm that the two criteria for this project are that: (1) deteriorated sections of circuits A8K and A9K are replaced; and (2) that each circuit's Long Term Emergency operating rating is increased to 550A.

b) Please confirm whether Alternatives 1 and 2 were the only two options considered. If other options were considered, please describe them and explain why these other options were not included among the transmission alternatives in the application.

Response:

a) Confirmed. This project aims to refurbish all deteriorated line sections of circuits A8K and A9K, and increase each circuit's Long Term Emergency operating rating to 550A, as requested by the IESO.

b) Please refer to Exhibit I, Tab 1, Schedule 2.

ENVIRONMENTAL DEFENCE INTERROGATORY #2

Reference:
Exhibit B-6-1, Attachment 1, page 8

Preamble:
The IESO report "End-of-Life Conductor Upgrades on the Ansonville x Kirkland (AxK) 115kV Lines" dated August 2021, states as follows:

> *"In the context of end-of-life replacement decisions, an option was evaluated in which circuits A8K/A9K are right-sized, i.e., further upgraded when they are replaced. This alternative is called the "Upgrade Option" and includes upgrading A8K/A9K to a summer planning rating of 550 Amperes. The IESO understands that a conductor with a summer planning rating of 550 Amperes is the highest rated conductor that can be installed using the existing tower structures."*

Interrogatory:
a) Please confirm whether the IESO's understanding (i.e., that a conductor with a summer planning rating of 550 Amperes is the highest rated conductor that can be installed using the existing tower structure) is correct. If not, what is the highest rated conductor that the existing tower structures can accommodate?

Response:
Confirmed. The IESO's understanding is correct.

The preferred alternative utilizing 411 kcmil ACSR/TW conductor meets Hydro One engineering standards; meets the IESO required 550 A summer Long Term Emergency rating; and minimizes the amount of additional structures requiring replacement in order to meet clearance and loading requirements.

The Hydro One standard transmission conductor one size larger than the 411 kcmil ACSR/TW would require the replacement of additional structures in order to meet clearance requirements, and would require the use of larger, more costly structures, in order to meet loading requirements.

ENVIRONMENTAL DEFENCE INTERROGATORY #3

Reference:
Exhibit B-6-1

Preamble:

> *"Hydro One's minimum standard size conductor for this range of application is 411 ACSR. All alternatives presented use this size of conductor, however the preferred alternative results in replacing more line with this sized conductor, and therefore results in greater loss reduction."*

Interrogatory:

a) Does Hydro One take the position that it was unable to seek OEB approval for a larger conductor than 411 ACSR even if this could cost-effectively avoid transmission losses (i.e., the net present value of the transmission loss reductions would be higher than the net present value of the incremental cost of the larger conductor)?

b) Was Hydro One or the IESO responsible for determining whether a larger conductor would be more cost-effective due to the value of incremental transmission loss reductions (i.e., greater than 411 ACSR)? Please provide Hydro One's view and confirm the IESO's view.

c) Please provide the name and title of the primary Hydro One engineers that were involved in the development of this project.

d) Please provide the name and title of the primary IESO engineers that were involved in the development of this project.

e) Did Hydro One and the IESO discuss the possibility of upsizing the conductors to cost-effectively reduce transmission losses? If yes, please provide the approximate dates of any such discussions, a summary of what was concluded, and any correspondence on that topic.

Response:

a) No, this is not Hydro One's position.

b) Hydro One's Response

Yes, Hydro One is ultimately responsible for determining the cost effectiveness of using a larger conductor within the context of any applicable transmission project where the need parameters have been established. This holds true even when factoring in specific considerations, such as the impact of different conductor/s on line loss reductions.

This part of the response to part b) has been provided by the IESO.

IESO Response

In general, the planning processes carried out by the IESO provide an opportunity to influence the energy losses associated with operating the transmission system, by carrying out key decisions on voltage level, high-level routing, and capabilities of both new and refurbished assets required to maintain system reliability. These decisions can, collectively or individually, have an impact on the overall system efficiency.

c) The names of the Hydro One employees are not pertinent and are out of scope of this proceeding.

d) The names of the IESO employees are not pertinent and are out of scope of this proceeding.

e) Hydro One and the IESO did not discuss the possibility of upsizing the 411 kcmil ACSR/TW conductor used in this project to the next larger standard Hydro One conductor to cost effectively reduce transmission losses. This is because any Hydro One standard conductor greater than the 411 kcmil ACSR/TW to achieve the requested 550A would be, at minimum, 25% heavier and therefore require significant additional structure replacements/modifications. Furthermore, the benefits to the greater transmission system, system losses included, are not solely constrained by the selection of this circuit's conductor. For example, operationally, system benefits could be constrained by the limits of other circuits along the system and/or terminal facilities. Given (i) the direction provided by the IESO to provide 550A along this circuit, and (ii) the fact that the IESO request could be achieved utilizing Hydro One's minimum standard conductor while minimizing structural modifications/reinforcements (i.e., minimizing capital costs), Hydro One did not further investigate any conductor alternatives over and above the selected 411 kcmil ACSR/TW conductor.

ENVIRONMENTAL DEFENCE INTERROGATORY #4

Reference:
Exhibit B-6-1

Preamble:

> *"Hydro One's minimum standard size conductor for this range of application is 411 ACSR. All alternatives presented use this size of conductor, however the preferred alternative results in replacing more line with this sized conductor, and therefore results in greater loss reduction."*

Interrogatory:

a) Did Hydro One consider any other size conductor other than the 411 ACSR for this application? If not, why not?

b) Please provide a list of the type and size of conductors that would also result in a summer planning rating of 550 Amperes. Presumably this will include a variety of larger conductors.

c) Please estimate the cost of the project based on the various potential conductors that would meet the required summer planning rating of 550A and include those estimates in the following table:

Conductor Alternatives – Capital Cost Comparison	
	Total Capital Cost
Conductor 1: 411 ACSR	$69.7 million
Conductor 2	
…	
Conductor n	

d) To assist us in determining whether a more detailed transmission loss analysis is unnecessary, please estimate annual transmission losses that would result from the various potential conductors that would meet the required summer planning rating of 550A and include those estimates in the following table. Please estimate the losses as if the lines were fully loaded 24/7/365. Note that this request is intended to assist in screening and is not a forecast.

Conductor Alternatives – Annual Transmission Loss Comparison for Screening	
	Estimated Transmission Loss
Conductor 1: 411 ACSR	X kwh
Conductor 2	Y kwh
…	…
Conductor n	

e) To assist us in determining whether a more detailed transmission loss analysis is unnecessary, please calculate the cost of the transmission losses set out in part (d) above at $120/MWh and provide the results in the following table:

Conductor Alternatives – Annual Transmission Loss Value (for Screening Only)	
	Estimated Transmission Losses Value
Conductor 1: 411 ACSR	$X
Conductor 2	$Y
…	…
Conductor n	

f) Please estimate annual transmission losses that would result from the various potential conductors that would meet the required summer planning rating of 550A and include those estimates in the following table. Please estimate the losses based on historic load data of Hydro One's choosing and make and state all necessary assumptions.

Conductor Alternatives – Annual Transmission Loss Comparison	
	Estimated Transmission Losses
Conductor 1: 411 ACSR	X kwh
Conductor 2	Y kwh
…	…
Conductor n	

g) Please estimate annual transmission losses assuming the load increases by 2% annually over 40 years starting from the amount listed in (f).

Conductor Alternatives – Transmission Loss Comparison – 40 Years			
	Estimated Annual Transmission Losses		
	Year 1	…	Year 40
Conductor 1: 411 ACSR ACSS	X kwh		
Conductor 2	Y kwh		
…	…		
Conductor n			

h) Please estimate the value of transmission losses listed in (g) based on the avoided cost figures published by the IESO as part of its latest Annual Planning Outlook for both capacity and energy and provide the results in the following table. Please provide the calculations used to derive costs from the avoided cost figures.

Conductor Alternatives – Transmission Loss Value – 40 Years			
	Estimated Annual Transmission Losses Value		
	Year 1	…	Year 40
Conductor 1: 411 ACSR ACSS	$X	…	
Conductor 2	…		
…			
Conductor n			

i) Please provide the equations necessary to determine the losses along the line in question based on the various conductor options that would meet the required summer planning rating of 550A. Please include a function to determine the losses based on the load (MW).

j) For the most recent year with available data, please provide a live excel spreadsheet showing the load on the line (MW) and the transmission losses on the line (MW) for every hour in that year. For that same year, please also provide HOEP and GA for every hour in the year.

<u>Response:</u>

a) Hydro One considered all conductors capable of meeting the IESO's required 550 A summer Long Term Emergency rating and concluded the preferred alternative utilizing 411 kcmil ACSR/TW conductor meets Hydro One engineering standards; meets the IESO required 550 A summer Long Term Emergency rating; and minimizes the amount of additional structures requiring replacement in order to meet clearance and loading requirements.

The Hydro One standard transmission conductor one size larger than the 411 kcmil ACSR/TW would require the replacement of additional structures in order to meet clearance requirements, and would require the use of larger, more costly structures, in other to meet loading requirements.

b) The table below lists the type and size of standard Hydro One transmission conductors that can achieve a summer planning rating of 550 Amperes. The first listed conductor is the smallest standard Hydro One transmission conductor and the conductor selected for use in this project.

Type and Size of Transmission Conductors used by Hydro One
Conductor 1: 411.4 kcmil ACSR/TW
Conductor 2: 477 kcmil ACSR
Conductor 3: 732 kcmil ACSR/TW and larger (See Note 1 below)

Note 1 - The 477 kcmil ACSR conductor is ~25% heavier than the 411.4 kcmil ACSR/TW conductor. This additional weight can be accommodated through refurbishment with larger and additional structure and associated hardware replacements. However, the 732 kcmil ACSR/TW conductor is ~75% heavier than the 411.4 kcmil ACSR/TW conductor and can only be practically achieved through building new lines at a high level estimated cost of $140M. For this reason, comparing conductors larger than 477 kcmil ACSR is not possible, as use of these conductors cannot be practically achieved through refurbishment and would require building new.

c) The table below lists the estimated cost of the project through the use of potential conductors that would meet the required summer planning rating of 550A through refurbishment. Comparing conductors larger than 477 kcmil ACSR is not possible, as use of these conductors cannot be practically achieved through refurbishment and would require building new.

Conductor Alternatives – Capital Cost Comparison	
	Total Capital Cost
Conductor 1: 411.4 kcmil ACSR/TW	$69.7 million
Conductor 2: 477 kcmil ACSR	$85.1 million
Conductor 3: 732 kcmil ACSR/TW and larger	Cannot be achieved through refurbishment

d) The MWh loss for the 411 kcmil ACSR conductor and the 477 kcmil ACSR conductor assuming the maximum forecast flow as occurring 24/7/365 are given in the table below.

Conductor Alternatives – Annual Transmission Loss Comparison for Screening	
	Estimated Transmission Loss (MWh)
411 ACSR	57111 MWh (peak losses = 6.5 MW)
477 ACSR	46533 MWh (peak losses = 5.3 MW)

Note: The 550A requirement corresponds to a Long Term Emergency (LTE) rating which is a temporary state and corresponds to the thermal rating one circuit would need to carry with the companion circuit out of service. This mode of operation and pre-contingency current flow is not expected to occur 24/7/365. For this analysis, pre-contingency flows were assumed to be 275A resulting in a 550A LTE scenario.

e) The cost of the transmission losses assuming peak flows 24/7/365 based on $120/MWh are provided below in table below.

Conductor Alternatives – Annual Transmission Loss Comparison for Screening	
	Estimated Transmission Loss Value ($)
411ACSR	57111MWh @ $120/MWh = $6,853,288
477ACSR	46533MWh @ $120/MWh = $5,583,950

f) The annual losses based on 2020 Flows are given the table below.

Conductor Alternatives – Annual Transmission Loss Comparison	
	Estimated Transmission Losses (MWh)
411ACSR	2072.0
477ACSR	1687.0

g) The estimate annual transmission losses assuming the load increases by 2% annually over 40 years starting from the amount listed in (f), above, are given in Table below.

No.	Year	Losses (MWh)		IESO Avoided Cost (2020$/MWh)	Avoided Cost Based on IESO APO		
		411 kcmil	477 kcmil		411kcmil	477kcmil	Difference
0	2020	2072.0	1687.0	$23	$47,656.00	$38,801.00	$8,855.00
1	2021	2154.9	1754.5	$23	$49,562.24	$40,353.04	$9,209.20
2	2022	2241.1	1824.7	$23	$51,544.73	$41,967.16	$9,577.57
3	2023	2330.7	1897.6	$29	$53,606.52	$43,645.85	$9,960.67
4	2024	2423.9	1973.6	$27	$55,750.78	$45,391.68	$10,359.10
5	2025	2520.9	2052.5	$28	$57,980.81	$47,207.35	$10,773.46
6	2026	2621.7	2134.6	$33	$60,300.04	$49,095.64	$11,204.40
7	2027	2726.6	2220.0	$32	$62,712.04	$51,059.47	$11,652.58
8	2028	2835.7	2308.8	$33	$65,220.53	$53,101.85	$12,118.68
9	2029	2949.1	2401.1	$33	$67,829.35	$55,225.92	$12,603.43
10	2030	3067.1	2497.2	$36	$70,542.52	$57,434.96	$13,107.56
11	2031	3189.7	2597.1	$36	$73,364.22	$59,732.36	$13,631.87
12	2032	3317.3	2700.9	$34	$76,298.79	$62,121.65	$14,177.14
13	2033	3450.0	2809.0	$35	$79,350.74	$64,606.52	$14,744.23
14	2034	3588.0	2921.3	$34	$82,524.77	$67,190.78	$15,333.99
15	2035	3731.6	3038.2	$37	$85,825.76	$69,878.41	$15,947.35
16	2036	3880.8	3159.7	$38	$89,258.79	$72,673.55	$16,585.25
17	2037	4036.0	3286.1	$39	$92,829.15	$75,580.49	$17,248.66
18	2038	4197.5	3417.6	$41	$96,542.31	$78,603.71	$17,938.61
19	2039	4365.4	3554.3	$44	$100,404.00	$81,747.85	$18,656.15
20	2040	4540.0	3696.4	$47	$104,420.16	$85,017.77	$19,402.40
21	2041	4721.6	3844.3	$47	$108,596.97	$88,418.48	$20,178.49
22	2042	4910.5	3998.1	$47	$112,940.85	$91,955.22	$20,985.63

No.	Year	Losses (MWh)		IESO Avoided Cost (2020$/MWh)	Avoided Cost Based on IESO APO		
		411 kcmil	477 kcmil		411kcmil	477kcmil	Difference
23	2043	5106.9	4158.0	$47	$117,458.48	$95,633.43	$21,825.06
24	2044	5311.2	4324.3	$47	$122,156.82	$99,458.76	$22,698.06
25	2045	5523.6	4497.3	$47	$127,043.10	$103,437.12	$23,605.98
26	2046	5744.6	4677.2	$47	$132,124.82	$107,574.60	$24,550.22
27	2047	5974.3	4864.2	$47	$137,409.81	$111,877.58	$25,532.23
28	2048	6213.3	5058.8	$47	$142,906.21	$116,352.69	$26,553.52
29	2049	6461.8	5261.2	$47	$148,622.45	$121,006.79	$27,615.66
30	2050	6720.3	5471.6	$47	$154,567.35	$125,847.07	$28,720.28
31	2051	6989.1	5690.5	$47	$160,750.05	$130,880.95	$29,869.10
32	2052	7268.7	5918.1	$47	$167,180.05	$136,116.19	$31,063.86
33	2053	7559.4	6154.8	$47	$173,867.25	$141,560.83	$32,306.41
34	2054	7861.8	6401.0	$47	$180,821.94	$147,223.27	$33,598.67
35	2055	8176.3	6657.1	$47	$188,054.82	$153,112.20	$34,942.62
36	2056	8503.3	6923.3	$47	$195,577.01	$159,236.69	$36,340.32
37	2057	8843.5	7200.3	$47	$203,400.09	$165,606.15	$37,793.94
38	2058	9197.2	7488.3	$47	$211,536.09	$172,230.40	$39,305.69
39	2059	9565.1	7787.8	$47	$219,997.54	$179,119.62	$40,877.92
40	2060	9947.7	8099.3	$47	$228,797.44	$186,284.40	$42,513.04

h) See above (g) for table include IESO Avoided Cost.

i) The losses have been determined based on the actual current flow in each circuit.

Line losses are calculated using the following equation;

Line Losses = $3*I^2R$
Where;
- I is the current flowing in the line, and
- R is the line resistance.

The current, I, can be calculated from the MW load by using the following formula;

I = $MW/(\sqrt{3}*Voltage)$

Annual losses are calculated using the standard assumption that there are 8,760 hours in a year.

j) Please refer to Attachment A to this response for a live model in MS Excel format. Please refer to Attachment B to this response for the 2020 Global Adjustment (GA) values. Please note that GA values are calculated on a monthly basis.

Hourly HOEP value for 2020 are publically available and can be found on IESO website.

Main HOEP Link: http://reports.ieso.ca/public/PriceHOEPAverage/

2020 HOEP Link:
http://reports.ieso.ca/public/PriceHOEPPredispOR/PUB_PriceHOEPPredispOR_2020.csv

ENVIRONMENTAL DEFENCE INTERROGATORY #4-J

This exhibit has been filed separately in MS Excel Format.

Year		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2015	1st Estimate ($/MWh)	55.49	69.81	36.04	67.05	94.16	92.28	88.88	88.05	82.70	63.71	76.23	114.62
	2nd Estimate ($/MWh)	61.61	40.95	57.40	92.68	97.30	97.68	84.13	73.55	71.91	71.93	124.48	88.09
	Actual Rate ($/MWh)	50.68	39.61	62.90	95.59	96.68	95.40	78.83	80.10	67.03	75.44	113.20	94.71
2016	1st Estimate ($/MWh)	84.23	103.84	90.22	121.15	104.05	116.50	76.67	85.69	70.60	97.20	122.71	105.94
	2nd Estimate ($/MWh)	92.14	96.78	102.99	111.77	114.93	93.60	84.12	70.50	91.48	117.80	115.00	78.72
	Actual Rate ($/MWh)	91.79	98.51	106.10	111.32	107.49	95.45	83.06	71.03	95.31	112.26	111.09	87.08
2017	1st Estimate ($/MWh)	66.87	105.59	84.09	68.74	106.23	119.54	106.52	115.00	127.39	102.12	111.64	83.91
	2nd Estimate ($/MWh)	86.77	84.30	68.86	102.18	127.76	125.63	101.97	104.76	98.95	119.73	96.69	96.69
	Actual Rate ($/MWh)	82.27	86.39	71.35	107.78	123.07	118.48	112.80	101.09	88.64	125.63	97.04	92.07
2018	1st Estimate ($/MWh)	87.77	73.33	78.77	98.10	93.92	133.36	85.02	77.90	84.24	89.21	122.35	91.98
	2nd Estimate ($/MWh)	63.70	77.05	85.95	100.74	131.99	102.39	81.23	73.24	86.60	119.98	105.40	70.67
	Actual Rate ($/MWh)	67.36	81.67	94.81	99.59	107.93	118.96	77.37	74.90	85.84	120.59	98.55	74.04
2019	1st Estimate ($/MWh)	67.41	96.57	81.05	81.29	128.60	124.44	135.27	72.11	129.34	178.78	107.27	85.69
	2nd Estimate ($/MWh)	83.06	82.36	75.75	124.88	130.49	147.72	88.54	109.74	163.92	118.86	101.09	90.66
	Actual Rate ($/MWh)	80.92	88.12	80.41	123.33	126.04	137.28	96.45	126.07	122.63	136.80	99.53	93.21
2020	1st Estimate ($/MWh)	83.23	124.51	104.32	137.07	92.93	115.00	103.05	102.32	115.73	149.54	116.70	107.04
	2nd Estimate ($/MWh)	99.93	114.35	112.12	115.00	115.00	115.00	94.93	106.22	127.92	132.66	114.20	100.31
	Actual Rate ($/MWh)	102.32	113.31	119.42	115.00	115.00	115.00	99.02	103.48	121.76	128.06	117.05	105.58

***See 2020 Deferral Information worksheet for additional details**

ENVIRONMENTAL DEFENCE INTERROGATORY #5

Reference:
Exhibit B-6-1

Preamble:

> *"Hydro One's minimum standard size conductor for this range of application is 411 ACSR. All alternatives presented use this size of conductor, however the preferred alternative results in replacing more line with this sized conductor, and therefore results in greater loss reduction."*

Interrogatory:

a) Please conduct an analysis assessing the cost-effectiveness of upsizing the conductor that compares the incremental costs to the incremental benefits (i.e., reduced transmission losses) over 40 years. Please express the losses as valued at HOEP and GA. Please express the result as an NPV figure. Please provide all the calculations, variables, and assumptions.

Response:

a) Using Hydro One's current evaluation procedures[1], Hydro One determined that the 411 kcmil conductor option was the preferred option on a cost-benefit basis for ratepayers compared to other alternatives, while still meeting the IESO's requested ampacity capability. Increasing the size of conductor would result in higher costs ultimately levied on ratepayers. Hydro One undertook, at the request of Environmental Defence, a 40-year net present value (NPV) analysis that compared the two discussed alternatives, a) 411 kcmil and b) 477 kcmil. The incremental NPV result of selecting the larger 477 kcmil conductor, compared to the preferred option over a 40 year time horizon, yields an incremental negative cost (i.e. additional cost to ratepayers) of $12.9M[2] using Hydro One's discount rate of 5.31%, or an incremental negative cost of $10.9M[3] using a discount rate of 1.5%. Both scenario calculations are provided in Tables 1 through 4 below. This NPV analysis, ultimately shows that the additional incremental cost of the larger 477 kcmil conductor will not be recovered over a 40-year timeframe.

[Hydro One notes that the above-requested analysis has yielded the same conclusion as Hydro One's analysis. This is similar to the analysis performed and presented in the recent OEB-approved[4] Leave to Construct application for the Hawthorne x Merivale Reconductoring (HMR) Project. In the HMR Project all parties concluded that the 1443 kcmil ACSR was the more cost-effective solution, as it pertains to line losses, that the higher cost 1780 kcmil ACSR solution, based on cost-benefit analysis. In the HRM Application, Environmental Defence's (ED's) consultant filed a NPV analysis whereby Hydro One used the same processes as used in this Application to evaluate Project's alternatives. ED suggested that the OEB ask Hydro One to improve its assessment of project alternatives with respect to transmission line loss evaluation and corresponding system wide benefits in future cases[5]. In its finding on this issue the OEB stated;

[1] Hydro One's line losses evaluation processes, and independent evaluation of those, are provided in Hydro One's 2023-27 transmission rate filing EB-2021-0110, currently before the OEB for approval. The primary Line Loss information references in the 2023-27 Application are; Exhibit B, Tab 2, Schedule 1, Sections 2.3 and Section 2.6, and Attachment #4 to the same Exhibit.
[2] As per the result of Table 1 and 2 below (based on discount rate of 5.31%).
[3] As per the result of Table 3 and 4 below (based on discount rate of 1.5%).
[4] EB-2020-0265 - Hawthorne x Merrivale Reconductoring Project – Leave to Construct S.92 Application
[5] EB-2020-0265, Decision and Order Page – April 22, 2021, page 14

> *"The OEB does not find this to be necessary in the context of this Application. As Hydro One indicated in its reply submission, line loss process details and guidelines will be provided in its next transmission rate filing application which is expected later in 2021."*[6]

As referenced above in footnote #1, Hydro One has now filed that evidence in its transmission rate filing, and the line losses information provided is consistent with the expectations of the OEB[7]*.]*

Hydro One used the following assumptions when performing the NPV analysis requested by Environmental Defence:

1. The cost for the 411 kcmil conductor is $75.7M vs. the cost for 477 kcmil conductor is $92.5M, an additional incremental cost of $16.8M.
2. There are no incremental revenues and/or operating and maintenance costs for the larger 477 kcmil conductor size, compared to the preferred option.
3. The energy cost is $120/MWh[8].
4. The annual energy savings for the upsized 477 kcmil conductor is 575 MWh.
5. Regarding the discount factor, two incremental NPV analyses were conducted:
    a) Table 1 and 2 used a discount factor of 5.31%, derived from information contained in Hydro One's OEB-approved Draft Rate Order for cost of capital parameters[9].
    b) Table 3 and 4 used a discount rate of 1.5%, similar to the follow-up interrogatory[10] from Environmental Defence in Hydro One's Richview TS by Trafalgar TS section 92 application (EB-2021-0136).
6. The transmission project capital expenditures are considered Class 47[11] assets for tax purposes and the terminal value of the present value of the tax shield after the 40 year period is included in the NPV.

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[6] EB-2020-0265, Decision and Order Page – April 22, 2021, pgs., 14,15
[7] EB-2019-0082 – OEB's Decision and Order, April 23, 2020, pgs. 58,59.
[8] Hydro One used $120/MWH (HOEP + GA) energy cost.
[9] EB-2019-0082 - Hydro One Networks' 2020-2022 Transmission Revenue Requirement, Draft Rate Order, May 28, 2020 – Exhibit 1.4 page 1.
[10] Hydro One's Richview TS by Trafalgar TS section 92 application (EB-2021-0136) follow up interrogatory #2 from Environmental Defence.
[11] For tax purposes in Canada, Class 47 assets are a class of Capital Cost Allowance (CCA) for Property acquired after February 22, 2005, that is classified as transmission or distribution equipment.

Table 1 - Incremental Cost NPV Analysis – Between Two Options: 411 kcmil vs. 477 kcmil conductors, Page 1

Incremental NPV analysis comparing two conductor options (in $k) **For 40 Years Ended December 31st, 2062**	**Total**	**Period 0**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) | Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income Tax Recovery | (Provision)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Incremental Capital Expenditures for the upsize	-16,791	-16,791	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	4,389	0	534	313	288	265	244	224	206	190	175	161	148	136	125	115	106	97	90	83	76	70	64
Incremental Line Loss Savings for the upsize	2,761	0	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69
Net Incremental Impact to Ratepayers for the upsize	**-9,641**	**-16,791**	**603**	**382**	**357**	**334**	**313**	**293**	**275**	**259**	**244**	**230**	**217**	**205**	**194**	**184**	**175**	**166**	**159**	**152**	**145**	**139**	**133**
Discount Factor Full Year Discount @ 0.053		1.0000	0.9496	0.9017	0.8563	0.8131	0.7721	0.7332	0.6963	0.6612	0.6278	0.5962	0.5661	0.5376	0.5105	0.4848	0.4603	0.4371	0.4151	0.3942	0.3743	0.3554	0.3375
Annual Net Present Value for the upsize		-16,791	573	345	306	272	242	215	192	171	153	137	123	110	99	89	81	73	66	60	54	49	45
Cumulative Incremental Net Present Value for the upsize	**-12,913**	**-16,791**	**-16,218**	**-15,874**	**-15,568**	**-15,296**	**-15,055**	**-14,839**	**-14,648**	**-14,476**	**-14,323**	**-14,186**	**-14,064**	**-13,953**	**-13,854**	**-13,765**	**-13,684**	**-13,612**	**-13,546**	**-13,486**	**-13,432**	**-13,382**	**-13,337**

Note: This Table uses discount rate of 5.31%.

Table 2 - Incremental Cost NPV Analysis – Between Two Options: 411 kcmil vs. 477 kcmil conductors, Page 2

Incremental NPV analysis comparing two conductor options (in $k)
For 40 Years Ended December 31st, 2062

	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	Terminal Value
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) | Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income Tax Recovery | (Provision)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	59	54	50	46	42	39	36	33	30	28	26	24	22	20	18	17	16	14	13	91
Incremental Line Loss Savings for the upsize	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	0
Net Incremental Impact to Ratepayers for the upsize	**128**	**123**	**119**	**115**	**111**	**108**	**105**	**102**	**99**	**97**	**95**	**93**	**91**	**89**	**87**	**86**	**85**	**83**	**82**	**91**
Discount Factor Full Year Discount @ 0.053	0.3205	0.3044	0.2890	0.2744	0.2606	0.2475	0.2350	0.2232	0.2119	0.2012	0.1911	0.1815	0.1723	0.1636	0.1554	0.1475	0.1401	0.1330	0.1263	0.1263
Annual Net Present Value for the upsize	41	38	34	32	29	27	25	23	21	20	18	17	16	15	14	13	12	11	10	12
Cumulative Incremental Net Present Value for the upsize	**-13,296**	**-13,259**	**-13,224**	**-13,193**	**-13,164**	**-13,137**	**-13,112**	**-13,090**	**-13,069**	**-13,049**	**-13,031**	**-13,014**	**-12,998**	**-12,984**	**-12,970**	**-12,958**	**-12,946**	**-12,935**	**-12,924**	**-12,913**

Note: This Table uses discount rate of 5.31%.

Table 3 - Incremental Cost NPV Analysis – Between Two Options: 411 kcmil vs. 477 kcmil conductors, Page 1

Incremental NPV analysis comparing two conductor options (in $k)
For 40 Years Ended December 31st, 2062

	Total	Period 0	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) | Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0
Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income Tax Recovery | (Provision)	0	0	0	0	0	0	0	0	0	0	0	0
Net Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Incremental Capital Expenditures for the upsize	-16,791	-16,791	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	4,426	0	534	313	288	265	244	224	206	190	175	161
Incremental Line Loss Savings for the upsize	2,761	0	69	69	69	69	69	69	69	69	69	69
Net Incremental Impact to Ratepayers for the upsize	**-9,605**	**-16,791**	**603**	**382**	**357**	**334**	**313**	**293**	**275**	**259**	**244**	**230**
Discount Factor Full Year Discount @ 0.015		1.0000	0.9852	0.9707	0.9563	0.9422	0.9283	0.9145	0.9010	0.8877	0.8746	0.8617
Annual Net Present Value for the upsize		-16,791	594	371	342	315	290	268	248	230	213	198
Cumulative Incremental Net Present Value for the upsize	**-10,952**	**-16,791**	**-16,197**	**-15,826**	**-15,484**	**-15,169**	**-14,879**	**-14,611**	**-14,362**	**-14,133**	**-13,919**	**-13,721**

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) | Cost Savings	0	0	0	0	0	0	0	0	0	0	0
Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income Tax Recovery | (Provision)	0	0	0	0	0	0	0	0	0	0	0
Net Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	148	136	125	115	106	97	90	83	76	70	64
Incremental Line Loss Savings for the upsize	69	69	69	69	69	69	69	69	69	69	69
Net Incremental Impact to Ratepayers for the upsize	**217**	**205**	**194**	**184**	**175**	**166**	**159**	**152**	**145**	**139**	**133**
Discount Factor Full Year Discount @ 0.015	0.8489	0.8364	0.8240	0.8118	0.7999	0.7880	0.7764	0.7649	0.7536	0.7425	0.7315
Annual Net Present Value for the upsize	184	172	160	150	140	131	123	116	109	103	97
Cumulative Incremental Net Present Value for the upsize	**-13,537**	**-13,366**	**-13,206**	**-13,056**	**-12,916**	**-12,785**	**-12,662**	**-12,546**	**-12,437**	**-12,334**	**-12,236**

Note: This Table uses discount rate of 1.5%.

Table 4 - Incremental Cost NPV Analysis – Between Two Options: 411 kcmil vs. 477 kcmil conductors, Page 2

Incremental NPV analysis comparing two conductor options (in $k)
For 40 Years Ended December 31st, 2062

	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	Terminal Value
Incremental Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental OM&A (Costs) | Cost Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Income Tax Recovery | (Provision)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Net Operating Cash Flows	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Incremental Capital Expenditures for the upsize	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield for the upsize	59	54	50	46	42	39	36	33	30	28	26	24	22	20	18	17	16	14	13	128
Incremental Line Loss Savings for the upsize	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	69	0
Net Incremental Impact to Ratepayers for the upsize	**128**	**123**	**119**	**115**	**111**	**108**	**105**	**102**	**99**	**97**	**95**	**93**	**91**	**89**	**87**	**86**	**85**	**83**	**82**	**128**
Discount Factor Full Year Discount @ 0.015	0.7207	0.7100	0.6995	0.6892	0.6790	0.6690	0.6591	0.6494	0.6398	0.6303	0.6210	0.6118	0.6028	0.5939	0.5851	0.5764	0.5679	0.5595	0.5513	0.5513
Annual Net Present Value for the upsize	92	88	83	79	76	72	69	66	64	61	59	57	55	53	51	50	48	47	45	70
Cumulative Incremental Net Present Value for the upsize	**-12,144**	**-12,056**	**-11,973**	**-11,894**	**-11,818**	**-11,746**	**-11,677**	**-11,610**	**-11,547**	**-11,486**	**-11,427**	**-11,370**	**-11,315**	**-11,263**	**-11,211**	**-11,162**	**-11,114**	**-11,067**	**-11,022**	**-10,952**

Note: This Table uses discount rate of 1.5%.

ENVIRONMENTAL DEFENCE INTERROGATORY #6

Reference:
Exhibit B-6-1

Preamble:

> *"Hydro One's minimum standard size conductor for this range of application is 411 ACSR. All alternatives presented use this size of conductor, however the preferred alternative results in replacing more line with this sized conductor, and therefore results in greater loss reduction."*

Interrogatory:

a) Please provide the capacity the various potential conductors that would meet the required summer planning rating of 550A and include those estimates in the following table:

Conductor Alternatives – Capacity Comparison	
	Capacity
Conductor 1: 411 ACSR	X MW
Conductor 2	
…	
Conductor n	

b) Please estimate the value of this additional capacity to the electricity system to the extent that it may allow for less costly energy and/or capacity.

Response:

a) In the below table, the maximum summer continuous operating capacities of 411.4 kcmil ACSR/TW and the two next larger standard Hydro One conductors are provided. These figures are calculated using the upper ORTAC limit of 127 kV.

Conductor Alternatives – Capacity Comparison	
	Capacity
Conductor 1: 411.4 kcmil ACSR/TW	108 MW
Conductor 2: 477 kcmil ACSR	122 MW
Conductor 3: 732 kcmil ACSR/TW and larger	(See Note 1 below)

Note 1 - The 477 kcmil ACSR conductor is ~25% heavier than the 411.4 kcmil ACSR/TW conductor. This additional weight can be accommodated through refurbishment with larger and additional structure and associated hardware replacements. However, the 732 kcmil ACSR/TW conductor is ~75% heavier than the 411.4 kcmil ACSR/TW conductor and can only be practically achieved through building new lines at a high level estimated cost of $140M. For this reason, comparing the capacity achieved by conductors larger than 477 kcmil ACSR is not relevant, as use of these conductors cannot be practically achieved through refurbishment and would require building new.

b) **This response has been provided by the IESO.**

Please refer to Exhibit I, Tab 1, Schedule 3 part a.

ENVIRONMENTAL DEFENCE INTERROGATORY #7

Reference:
Exhibit B-6-1, Attachment 1, page 8

Preamble:
The IESO report "End-of-Life Conductor Upgrades on the Ansonville x Kirkland (AxK) 115kV Lines" dated August 2021, states as follows:

> *"In the context of end-of-life replacement decisions, an option was evaluated in which circuits A8K/A9K are right-sized, i.e., further upgraded when they are replaced. This alternative is called the "Upgrade Option" and includes upgrading A8K/A9K to a summer planning rating of 550 Amperes. The IESO understands that a conductor with a summer planning rating of 550 Amperes is the highest rated conductor that can be installed using the existing tower structures."*

Interrogatory:
a) Please describe and estimate the cost of the tower modifications or replacements that would be required for the various potential conductors that would meet the required summer planning rating of 550Amperes and include those in the following table:

Conductor Alternatives – Tower Modification Comparisons		
	Description of Tower Modifications	Estimated Cost of Tower Modifications
Conductor 1: 411 ACSR		
Conductor 2		
…		
Conductor n		

Response:
a) The table below summarizes the required work and estimated cost to modify structures for the project through the use of potential conductors that would meet the required summer planning rating of 550A through refurbishment. Comparing conductors larger than 477 kcmil ACSR is not possible, as use of these conductors cannot be practically achieved through refurbishment and would require building new.

Conductor Alternatives – Tower Modification Comparisons		
	Description of Tower Modifications	Estimated Cost of Tower Modifications
Conductor 1: 411.4 kcmil ACSR/TW	Replacement of 1246 existing wood pole structures.	$29.1 million
Conductor 2: 477 kcmil ACSR	Replacement of a minimum of 1300 wood pole structures, where the replacements would need to be with larger/more reinforced structures. In addition, this alternative will require the reinforcement or replacement of 18 lattice steel structures (towers).	$37.4 million
Conductor 3: 732 kcmil ACSR/TW and larger	See Note 1 below	See Note 1 below

Note 1 - The 477 kcmil ACSR conductor is ~25% heavier than the 411.4 kcmil ACSR/TW conductor. This additional weight can be accommodated through refurbishment with larger and additional structure and associated hardware replacements. However, the 732 kcmil ACSR/TW conductor is ~75% heavier than the 411.4 kcmil ACSR/TW conductor and can only be practically achieved through building new lines at a high level estimated cost of $140M. For this reason, comparing conductors larger than 477 kcmil ACSR is not possible, as use of these conductors cannot be practically achieved through refurbishment and would require building new.

POLLUTION PROBE INTERROGATORY #1

Reference:
Ex. B, T3, Sch.1

Interrogatory:

a) Current distributed energy resource (DER) capacity in Ontario is currently approximately 5.1 MW based on IESO information. What incremental DER capacity will this project enable if approved and constructed? Please provide details.

b) Please explain how this project will support increased DER capacity in Ontario.

c) Incremental capacity can compete with more cost-effective local DER options. Please explain how this project would minimize increasing barriers to local DER solutions, including but not limited to CDM, storage and renewable generation.

d) Please explain what supply and demand assumptions have been made in regards to increased electrification in Ontario over the life of the proposed assets.

Response:
This response has been provided by the IESO.

a) The purpose of the project (i.e., the Upgrade Option) is to reliably supply the demand in the area in a cost-effective manner. The purpose of the project is not to enable DERs, nor does it directly enable the connection of DERs.

b) Please see response to part a) above.

c) The project (i.e., the Upgrade Option) does not address barriers to local DER solutions; the purpose of the project is to reliably supply the demand in the area in a cost-effective manner.

As part of a separate initiative, the IESO is currently implementing recommendations, made as part of the Regional Planning Process Review engagement which was completed in May 2021, to address barriers to non-wires alternatives in regional planning. A status update of this work was provided in October 2021 as part of the IESO's stakeholder engagement days. Please see the IESO website[1] for additional details.

The demand and supply assumptions in the local area are described in Exhibit B-6-1, Attachment 1, Table 1 and Table 2. The IESO did not consider increased electrification in Ontario beyond the industrial customer expansions and potential new mining development included in the forecast as this was not relevant to the study to inform the end-of-life replacement strategy for circuits A8K/A9K.

[1] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Completed/Regional-Planning-Review-Process; and,
https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derr/derr-20211019-presentation.ashx

POLLUTION PROBE INTERROGATORY #2

Reference:
Ex. B, T3, Sch.1

Interrogatory:
Please explain why an upgrade is more beneficial than maintenance or a like-for-like replacement.

Response:
The benefits of the proposed project are outlined in the following sections of the prefiled evidence:

- Exhibit B, Tab 5, Schedule 1;
- Exhibit B, Tab 6, Schedule 1; and
- Exhibit B, Tab 6, Schedule 1 Attachment 1.

The IESO's report included as Exhibit B, Tab 6, Schedule 1 Attachment 1 describes the rationale for increasing the rating of the A8K/A9K circuits from 390 Amperes in the Base Option, to a summer planning rating of 550 Amperes in the Upgrade Option. As per Exhibit B, Tab 6, Schedule 1 Attachment 1, the Upgrade Option was found to ensure reliability of the local area at the least cost. In this evidence, the Base Option is equivalent to the like-for-like replacement of circuits A8K/A9K.

POLLUTION PROBE INTERROGATORY #3

Reference:
Ex. B, T5, Sch.1

Interrogatory:

a) Please describe what DER or non-wires alternatives were assessed as options and how they compared in the cost benefit assessment.

Response:
The reference provided addresses the cost-benefits of the transmission alternatives considered to address the IESO need identified in Exhibit B, Tab 3, Schedule 1. Therefore, DER and non-wires alternatives were not included as part of the leave to construct evidence.

As described in Exhibit B, Tab 3, Schedule 1, the IESO has studied the asset replacement strategy for circuits A8K/A9K as part of their planned end-of-life. Both alternatives considered as part of the end-of-life for circuits A8K/A9K require additional local generation support in order to reliably supply the forecasted demand in the area. In both cases, the IESO considered non-wires alternatives to provide this support through output from the existing Northland Power natural-gas fired generation complex until its contract expiry in 2030, and replacement gas-fired generation in 2031 and beyond, which is one of the lowest cost options available. Note that other non-wires alternatives were ruled out given their comparative cost and the magnitude and estimated duration of the local generation support required to ensure reliability.

POLLUTION PROBE INTERROGATORY #4

Reference:
Ex. B, T7, Sch.1

Interrogatory:
What are the environmental and socio-economic mitigation costs included in the project cost estimate and how were they developed?

Response:
To develop the project's Environmental and Socio-Economic mitigation plan, feasible alternatives were identified, compared and evaluated to determine a preferred alternative. To evaluate the alternatives, a series of criteria were developed to assess each alternative following the recommendations of the Provincial Policy Statement (PPS). The evaluation of each alternative was based on available background data, including preliminary field investigations and desktop background reviews.

The alternatives were compared using a reasoned argument method, by assessing the advantages and disadvantages that each alternative had against the established criteria, to determine a preferred alternative. As a last step, a summary of potential environmental effects for the preferred alternative was generated and mitigation measures were developed.

Cost for these mitigation measures is then estimated following Hydro One's standard estimating process. The estimated environmental and socio-economic mitigation cost for this project is approximately $1M.

POLLUTION PROBE INTERROGATORY #5

Reference:

Ex. B, T7, Sch.1

Interrogatory:

a) Was an Environmental Assessment conducted for the proposed project? If yes, please provide a copy. If not, please indicate why not or when one will be completed.

b) Have environmental and socio-economic mitigation plans been developed for the proposed route? If yes, please provide a copy. If not, please indicate why not or when they will be completed.

Response:

a) Hydro One is currently assessing the project following the Full Class Environmental Assessment process as per the Class EA for Minor Transmission Facilities (Hydro One, 2016). The draft Environmental Study Report (ESR) has been released for a 30-day public review starting October 18, 2021. The draft ESR can be found on the project website at: www.hydroone.com/a8ka9k. Hydro One anticipates filing the Notice of Completion by end of December, 2021.

b) Environmental and socio-economic mitigation plans have been developed for the Project. Details can be found within the draft Environmental Study Report.

POLLUTION PROBE INTERROGATORY #6

Reference:

Ex. B, T7, Sch.1

Reference: Approvals and Permits – "there is a risk of delays being encountered in obtaining required approvals including Environmental Assessment and Leave to Construct."

Interrogatory:

a) Please explain in more detail the risks related to the Environmental Assessment and what Hydro One is doing to mitigate that risk.

b) Please explain how Leave to Construct approval can be granted if the completion of the Environmental Assessment process is not successful?

Response:

a) The typical risks related to the Environmental Assessment (EA) process include the risk of receiving a request to elevate to a higher level of study (i.e., requiring comprehensive EA approval before being able to proceed) or that conditions be imposed (e.g., require further studies) throughout the consultation process and 30-day public review period of the Environmental Study Report (ESR). However, these requests can only be made on the grounds that the requested order may prevent, mitigate or remedy adverse effects and constitutionally protected Aboriginal and treaty rights. The Ministry of Environment, Conservation and Parks will not consider requests on other grounds. Hydro One originally assessed the project following the Class EA Screening process, and as a result of consultation with Indigenous communities and interested stakeholders, voluntarily elevated to assess the project through a Full Class EA process. Hydro One is putting in all effort towards engaging and adequately consulting with Indigenous communities and interested stakeholders on the Project.

There is a risk that issues or concerns regarding the project may arise from public review of the draft ESR and Hydro One may not be able to address those concerns adequately. To mitigate this risk, Hydro One conducted archaeological, cultural and heritage assessments and field surveys of the study area to ensure that any potential impacts have been identified and mitigation measures put in place. If issues arise during the review period of the ESR such that Hydro One receives a request to elevate the EA, there is a risk that the construction schedule may be impacted. Hydro One is engaging in thorough consultation with all stakeholders to ensure that all issues and concerns are addressed in a timely manner and addressed to the satisfaction of interested stakeholders.

b) The approval of the leave to construct application and the Environmental Assessment are issued by two distinct regulators. It is not uncommon for the OEB to issue a leave to construct approval on a project subject to all other approvals necessary to complete the project being obtained. Please refer to Exhibit I, Tab 1, Schedule 22 for a list of standard conditions of approval attached to leave to construct approvals issued by the Ontario Energy Board.

POLLUTION PROBE INTERROGATORY #7

Reference:

Ex. B, T7, Sch.1

Interrogatory:

a) Have the existing assets being replace by this project been fully depreciated? If not, please indicate the current amount not depreciated.

b) Is the estimated cost of the project net of salvage value against the existing assets being retired?

c) What is the estimate salvage value of the proposed assets to be retired and who receives these benefits?

Response:

a) All original vintage components of this line have been fully depreciated. Though there are segments of line that have been sustained over the years which are of newer vintage, this project was designed to minimize the replacement of components that have remaining useful life. Please refer to Exhibit I, Tab 1, Schedule 12.

b) The estimated salvageable material value being removed will be offset by the waste removal cost.

c) The net credit for salvageable material for this project will be negligible as it will be offset by the waste removal cost.

POLLUTION PROBE INTERROGATORY #8

Reference:

Ex. B, T7, Sch.1

Interrogatory:

a) Is construction of this project contingent on capital approval in EB-2021-0110? If not, where will the capital expenditure approved by the OEB.

Response:

Though Hydro One’s capital portfolio will be reviewed as part of EB-2021-0110, commencing construction on this project is not contingent on capital approval in EB-2021-0110. Hydro One’s capital portfolio is approved by the OEB. Hydro One will manage any required changes to its capital portfolio via a redirection process.