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BY EMAIL AND RESS

October 8, 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-2021-0136 – Hydro One Networks Inc. Leave to Construct Application – Richview TS by Trafalgar TS Reconductoring Project – Interrogatory Responses

Hydro One Networks Inc. (Hydro One) is submitting written responses to the Ontario Energy Board ("OEB") staff, City of Mississauga, Environmental Defence, Association of Power Producers of Ontario, and Capital Power Corporation interrogatories on Hydro One's Richview TS by Trafalgar TS Reconductoring Project consistent with the timing outlined in the OEB's Procedural Order No. 1.

In responding to the interrogatories, Hydro One is providing certain informational data separately on a confidential basis, consistent with the OEB's rules. Hydro One has filed a separate Application asking the OEB to approve confidential treatment of that data.

Additionally, in the same Application, also filed today, October 8, 2021, Hydro One is asking for individual's names and personal information contained in another Attachment which forms reponses to these interrogatories, to remain redacted, as the non-disclosure of that information outweighs the public interest.

An electronic copy of the confidential information will be provided to the OEB (via email) and shall not be used by any party for any purpose other than the matters at hand.

An electronic copy of the interrogatory responses has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Joanne Richardson

c/ EB-2021-0136 Intervenors (Electronic only)

OEB STAFF INTERROGATORY #1

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 3, pages 7 – 8

Preamble:
The reference above discusses conservation, new supply resource and import alternatives to the Richview by Trafalgar Reconductoring Project.

Interrogatory:
a) Do the resources to the west of FETT that would be enabled to flow east towards Toronto by the proposed reconductoring project already exist or are already planned for (or some combination of the two)? In other words, would the Richview by Trafalgar Reconductoring Project allow Ontario to make use of existing or already planned resources to the west of FETT and therefore obviate the need to develop new resources in an effectively equivalent amount to the east of FETT (i.e., to address FETT limitations projected by approximately 2026)? If not, please clarify.

b) If so, would the IESO agree that this represents a cost advantage of the proposed Richview by Trafalgar Reconductoring Project compared to the east-of-FETT alternatives considered by the IESO in the reference above, in addition to the feasibility considerations considered by the IESO? If not, please clarify.

Response:
The following response has been provided by the IESO.

a) The proposed reconductoring project eliminates the requirement to locate 2,000 MW east of FETT by 2026, however, there is still a capacity need in the province and new resources east of FETT could help meet that need. The RTR Project would not obviate the need to acquire new resources in the province. As stated on page 7 of Exhibit B, Tab 1, Schedule 1, Attachment 3, there is an overall need for capacity in Ontario (province-wide) due to increasing demand for electricity and the retirement of Pickering GS combined with nuclear unit outages for refurbishment. For the year 2026, that amount was determined to be about 5,200 MW after re-acquiring Lennox GS and 3,400 MW assuming all other resources with expiring contracts in the province are re-acquired. The proposed RTR Project will remove the constraint that 2,000 MW of those new resources must be located east of the FETT interface.

b) By providing flexibility to acquire new resources west of the FETT interface, the proposed RTR Project should provide for greater competition amongst supply resources and ultimately lead to ratepayer savings. The IESO's assessment of ratepayer savings is conceptual in nature. The IESO has not calculated the value of the potential savings associated with greater competition and does not believe it would be possible to do so with any degree of precision at this time.

OEB STAFF INTERROGATORY #2

Reference:

(1) Exhibit B, Tab 3, Schedule 1, Attachment 3, page 6
(2) Exhibit B, Tab 3, Schedule 1, Attachment 3, page 7
(3) Exhibit B, Tab 3, Schedule 1, Attachment 3, page 10
(4) Exhibit B, Tab 3, Schedule 1, Attachment 3, page 8

Preamble:

The first reference shows capacity needs east of FETT to meet transmission security that range between 4,950 MW and 5,600 MW by 2034. These needs will reduce to between 1,800 MW and 2,250 MW in 2026 once the extension to the Lennox GS contract is negotiated.

The first reference also states that supply capacity east of the FETT interface will be needed "in the summer of 2023 when the Lennox GS contract expires in 2022" and identifies "further significant needs starting in 2026 after Pickering GS retires". The reference also states that "generating stations located east of FETT with expiring contracts around 2030 further adds to this need (Portland GS, Goreway GS, Halton Hills GS and York Energy Centre GS)."

The second reference states that "1850 MW to 2250 MW of supply is required to maintain security east of the FETT interface by 2026".

The third reference shows that that the proposed Richview by Trafalgar Reconductoring Project would increase FETT capacity by 2,150 MW (all in service).

The fourth reference states "depending on the outcomes of […] future provincial resource acquisitions, additional incremental increase in FETT transfer capability may be recommended as a second stage."

<u>Interrogatory:</u>

a) Please confirm that capacity needs east of FETT beyond the year 2026 exceed the capacity provided by recontacting Lennox GS and implementing the proposed Richview by Trafalgar Reconductoring Project. If confirmed, please comment on why a larger transmission upgrade was not proposed given that capacity needs are projected to arise even if Lennox GS is recontacted.

b) If not confirmed, please clarify.

c) Please comment on any key practical considerations, such as upstream or downstream constraints, that would limit the suitability or feasibility of implementing a larger upgrade to the Richview by Trafalgar circuits than proposed in this application.

d) Please explain whether the proposed upgrade will provide value even if additional incremental increases in FETT transfer capability are eventually implemented as a second stage. Please clarify whether those potential future increases will reduce the usefulness and cost effectiveness of the currently proposed upgrade.

e) Please explain whether and how the proposed upgrade will provide value even if expiring generation contracts around 2030 are replaced in the east. Please confirm and clarify whether replacing/recontracting/or otherwise making up for those expiring generation contracts will reduce the usefulness and cost effectiveness of the currently proposed upgrade.

<u>Response:</u>

The following response has been provided by the IESO.

a) Confirmed. The IESO assessed but did not recommend a larger transmission upgrade for the following reasons:

    1. The recommended transmission upgrade will be sufficient to meet the need for the foreseeable future if existing resources east of FETT are re-acquired. Furthermore, even if not all existing resources are re-acquired post-2026 there is a high likelihood that some of the new generation required to meet the provincial capacity need will be sited in eastern Ontario. Hence, there is not an urgency to pursue further upgrades to the FETT interface nor are we expecting that further upgrades would be required.

2. The proposed reconductoring project provides FETT transfer capacity of over 7,000 MW with all elements in-service. While there are no reliability standard requirements that restrict the ability to enhance a single transmission interface, relying on a single transmission interface with greater transfer capability than what the project provides creates concerns of system resilience for extreme events that have the potential to interrupt the entire interface (e.g., a tornado, plane crash, etc.), i.e., the "too many eggs in one basket" concept.

3. There are incremental upgrade options that can be implemented at a later date, if necessary. These upgrades would not reduce the usefulness and cost effectiveness of the project nor would it make any aspect of the project redundant.

b) Not applicable in light of the response to question a).

c) Please see response to question a).

d) Please see response to question a).

e) Table 1, below, shows the need east of FETT with all contracts of the resources located east of FETT reacquired without upgrading FETT interface. The proposed RTR Project would continue to have value in providing the transmission security need and the flexibility to acquire new resources for the province without the specific requirement to be located east of FETT. It should be noted that this assessment assumes continued operation of Lennox GS to 2034. The need could be higher if some of the resources with expiring contracts (which includes aging Lennox GS) do not continue to operate.

Table 1 – Need East of FETT (MW)

Demand Forecast	2026	2027	2028	2029	2030	2031	2032	2033	2034
Scenario 1	2,250	1,550	1,650	1,900	2,150	1,800	1,950	1,600	1,800
Scenario 2	1,800	1,000	1,250	1,450	1,650	1,250	1,350	1,000	1,100

OEB STAFF INTERROGATORY #3

Reference:
Exhibit B, Tab 1, Schedule 1, Attachment 3, pages 10 – 11

Preamble:
The reference compares the Richview by Trafalgar Reconductoring Project to a transmission alternative (called Alternative 2). The estimated cost of Alternative 2 is $88 Million. The references states that Alternative 2 would displace the need for other transmission, providing a benefit of about $23M. The reference states that “even with this credit […] the cost of Alternative 2 is still expected to be higher” than the Richview by Trafalgar Reconductoring Project.

Interrogatory:

a) Please clarify whether the estimated $23 Million credit is already factored into the estimated $88 Million cost of Alternative 2 (i.e. without the credit, would the cost of Alternative 2 be $88 Million + $23 Million credit = $111 Million, or would the credit reduce the $88 Million estimate by $23 Million for an effective cost of $65 Million?).

b) Whether or not the $23 Million credit is already factored into the $88 Million cost of Alternative 2, would the IESO agree that the cost of Alternative 2 per long term MW of increase is higher compared to the proposed Richview by Trafalgar Reconductoring Project as outlined in Table 3 (both from the perspective of “all in service” or “element out of service” conditions)? If yes, please briefly illustrate. If not, please clarify.

Response:
This response has been provided with collaboration from Hydro One and the IESO.

a) The $23M credit has not been factored into the estimated $88M cost of Alternative 2. Factoring in the credit would result in an effective cost of $65M for Alternative 2.

b) Yes, the IESO concurs that the cost of Alternative 2, on a dollar per megawatt basis, is more costly than the proposed RTR Project’s dollar per megawatt cost. The proposed RTR Project, as detailed in Hydro One’s Application, provides a greater long-term transfer capability at a lower cost, compared to the alternative. The costs per MW is illustrated in Table 1, below.

1 **Table 1 – Project Cost per MW**

Alternatives (Estimated Project Cost)	Incremental increase all in-service Transfer Capability (MW)	Cost / MW ($K)	Incremental increase with one element out-of-service Transfer Capability (MW)	Cost / MW ($K)
RTR Project ($61 M)	2,150	$28	1,550	$39
Alternative 2[1] ($65 M)	1,700	$38	1,250	$52

[1] Including the $23M Credit

OEB STAFF INTERROGATORY #4

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

Preamble:
The Richview by Trafalgar Reconductoring Project includes the replacement of the existing skywire atop the tower series that carries circuits R14T/R17T with OPGW between Richview TS and Trafalgar TS. The existing skywire was installed in 1985.

Interrogatory:
a) Please confirm that there is, or will be, a need to replace the existing skywire, even if not for the Richview by Trafalgar Reconductoring Project. Otherwise, please clarify. If the need is in the future, please indicate when and the cause of the need.

b) Please clarify whether a certain standard or set of standards guides the need to replace the existing skywire.

Response:
a) Confirmed. Sections of the existing skywire located on the towers carrying circuits R14T/R17T close to Trafalgar TS and close to Richview TS need to be replaced in the near future as the system fault current is approaching the existing skywire's current carrying capability. This scope of work would have been required even if the RTR Project were not going ahead.

The RTR Project provides the opportunity to replace the existing skywire with an Optical Ground Wire (OPGW) sized to provide the appropriate current capability required. The OPGW will provide additional fiber optic communication capacity and path diversity for the required 'protection signals' between Richview TS and Trafalgar TS. Performing circuit reconductoring and the replacement of the skywire with OPGW is both cost-effective (i.e. reduces the duplication of mobilization and set-up costs in the same location compared to if they were to be performed separately) and operationally-efficient (i.e. taking advantage of the reconductoring project's IESO-approved circuit outages).

b) Yes. Hydro One has internal standards[1] for skywire replacement that follows best-practices. The standards dictate that installed skywire needs to be in a good condition and be able to carry out its function of conducting the short circuit current under system fault conditions. Skywire is replaced generally for one of two reasons; a) conductor deterioration (i.e. poor condition) or, b) inadequate short circuit capacity.

Hydro One's skywire population is monitored through its condition assessment program. Under this program, skywire is regularly tested for deterioration and work is scheduled and undertaken to replace any skywire that has deteriorated beyond an acceptable level.

Hydro One also screens skywire to ensure that they have adequate capacity to carry the highest expected fault current. The screening is done as part of the system assessment whenever the system is refurbished, reinforced, or new generation is connected.

[1] These standards are consistent with Institute of Electrical and Electronics Engineers (IEEE) Standard 1863-2019 - Guide for Overhead AC Transmission Line Design

OEB STAFF INTERROGATORY #5

Reference:
(1) Exhibit E, Tab 1, Schedule 1, Attachment 2
(2) Exhibit E, Tab 1, Schedule 1, Attachment 3

Preamble:
Hydro One states that its proposed form agreements were included in and approved by the OEB in 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 Richview by Trafalgar Reconductoring Project, and explain any such differences.

Response:
a) There are no substantive differences between the proposed form agreements provided for this project, compared to other form agreements approved by the OEB in recent filings, specifically EB-2019-0077 and EB-2018-0117.

OEB STAFF INTERROGATORY #6

Reference:
Exhibit E, Tab 1, Schedule 1

Preamble:
The reference above identifies the land right agreements that Hydro One proposes to use to obtain any identified land rights for the Richview by Trafalgar Reconductoring Project.

Interrogatory:
a) Please confirm that all impacted landowners will have the option to receive independent legal advice regarding the proposed land agreements.

b) Please clarify whether Hydro One has committed to or will commit to reimbursing landowners for reasonably incurred legal fees associated with the review and execution of the necessary land rights agreements.

Response:
a) Confirmed, impacted landowners will have the option to receive independent legal advice.

b) Confirmed. Hydro One is committed to reimbursing landowners that Hydro One identifies will be impacted by the RTR Project, for the reasonably incurred fees for independent legal advice associated with the review and execution of the necessary land rights agreements.

OEB STAFF INTERROGATORY #7

Reference:

Exhibit B, Tab 1, Schedule 1

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:

a) Hydro One agrees to the standard OEB conditions of approval listed above.

OEB STAFF INTERROGATORY #8

Reference:

(1) Exhibit B, Tab 1, Schedule 1, p. 4.
(2) Exhibit B, Tab 3, Schedule 1, p. 2.
(3) Exhibit B, Tab 3, Schedule 1, Attachment 1
(4) Exhibit B, Tab 3, Schedule 1, Attachment 2
(5) Exhibit B, Tab 3, Schedule 1, Attachment 3

Preamble:

At reference (1), Hydro One states that the cost of the transmission line and related facilities for which it is seeking OEB approval is approximately $60.9 million, of which $56.3 million is capital and will be added to rate base, and $4.6 million is removals.

Reference (3) is the IESO letter recommending that Hydro One proceed with the Richview by Trafalgar Reconductoring Project and is dated December 10, 2020.

Reference (4) is Hydro One's September 9, 2020 memorandum cited by the IESO in its recommendation letter. In it, Hydro One states that the estimated cost to complete the project is $47.7M. At reference (2), Hydro One states that the cost estimate provided in the memorandum "informed the decision and direction that the IESO provided to Hydro One in its [recommendation] Letter."

Reference (5) is the IESO report entitled "Trafalgar TS x Richview TS 230 kV line upgrade: Need and Selection of the Preferred Plan" and is dated July 12, 2021. In its report, the IESO stated "[a]t the time the IESO recommended Hydro One to proceed with Alternative 1 in the IESO letter to Hydro One dated December 18, 2020, the cost estimate for Alternative 1 was $48M. Subsequently, Hydro One has indicated the cost estimate now stands at $61M after further reviews."

Interrogatory:

a) At reference (5), the IESO describes that the cost estimate for Alternative 1 was $48 million, but now stands at $61 million after further reviews. Please describe the further reviews undertaken by Hydro One that resulted in the revised cost estimate. Please also describe the drivers of the additional cost as well as the reasons these drivers were previously unknown.

b) Please identify the level of confidence associated with the revised $61 million estimate. E.g., is the estimate subject to the same 30%/-20% confidence as the $47.7M estimate in the September 9, 2020 memorandum?

c) Alternative 2 as described at reference (5) has an estimated cost of $88 million. Please identify the level of confidence associated with the $88 million estimate. E.g., is the estimate subject to a similar 30%/-20% confidence?

d) Please described the process used to determine Alternative 2's cost estimate of $88 million.

e) At reference (5) the IESO states that Alternative 2 would displace the need for transmission enhancements that increase the supply to Richview South and provide a benefit of about $23 million. The IESO further stated that even with this benefit and the higher cost of Alternative 1, the cost of Alternative 2 is still expected to be higher than Alternative 1. Please describe how the $23 benefit was calculated and indicate the level of confidence associated with it.

<u>Response:</u>

a) Hydro One's standard internal process was followed to prepare the revised estimate. The project plan and schedule were updated based on the project conditions and a new risk workshop was undertaken to determine the revised contingency amount. The estimate was also updated based on the latest available applicable rates (such as hardware, procurement and installation costs with revised labour, material, overhead and rental rates). Site walkthroughs were undertaken this year by the project team to identify and map access and craning requirements.

Table 1, below, provides a comparison of the current Richview by Trafalgar Reconductoring Project (RTR) Project estimate of $60.9M with the previously-provided estimate of $47.7M provided to the IESO, and referred to in Reference 4 of the interrogatory, above.

Table 1

Category	**Costs**		**Increase ($M)**
	Reference (4) ($M)	**Current S.92 Costs ($M)**	
Project Management	1.4	1.4	0.0
Real Estate	0.2	0.2	0.0
Engineering	0.8	1.5	0.7
Procurement	11.5	14.6	3.1
Construction	21.3	28.2	6.9
Commissioning	0.1	0.1	0.0
Contingency	2.2	3.0	0.8
Interest	2.6	2.3	-0.3
Overhead	4.0	5.0	1.0
Removals	3.6	4.6	1.0
Total	**47.7**	**60.9**	**13.2**

The main contributors to the increase in costs from the initial project estimate prepared in 2020 and the current 2021 RTR Project estimate are based on increased project maturity as identified below:

- Additional access roads to support crane access requirements, undetected due to limited site walkthroughs resulting from pandemic measures
- Additional crane pads to safely access all towers
- Increase in hardware, procurement and installation costs with revised labour, material, overhead and rental rates
- Updated risk evaluation resulting in increased contingency

b) Yes, the current RTR Project estimate has the same accuracy level (+30%/-20%) as the $47.7M estimate in the September 9, 2020 memorandum. The contributing factors of the cost difference are based on increased project maturity and listed in the response to part a) above.

c) The $88M cost for project Alternative # 2 is a planning estimate and has an accuracy level of (+100/-50%).

d) The $88M cost estimate for Alternative #2 was derived using transmission line unit costs, equipment unit costs, and similar prior project unit costs.

e) The $23M estimate is a budgetary estimate for the Richview TS x Manby TS line project. It has an accuracy of (+50%/-30%).

OEB STAFF INTERROGATORY #9

Reference:

(1) Exhibit B, Tab 7, Schedule 1, page 2
(2) Exhibit B, Tab 7, Schedule 1, Table 1, page 1

Preamble:

The first reference above outlines project risks, including Hydro One's estimated top four project risks. The second reference states the total estimated project cost of $56.2 million, which includes a contingency cost estimate of $2.7 million. This contingency cost estimate represents approximately 5% of the pre-contingency estimate.

Interrogatory:

a) Please explain the methods Hydro One used to assess project risks for the Richview by Trafalgar Reconductoring Project and please clarify how Hydro One's contingency estimate relates to that analysis. Through its response, Hydro One is also requested to articulate why the contingency cost estimate is appropriate.

b) Please describe how the contingency cost estimate for the Richview by Trafalgar Reconductoring Project compares to contingency cost estimates developed for similar Hydro One projects.

c) How would Hydro One characterize the confidence of the cost estimate for the Richview by Trafalgar Reconductoring Project? What method did Hydro One use to estimate its confidence?

d) How did Hydro One develop its estimates and confidence 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 $2.9M.
- 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 RTR Project is within the range of 5% to 15% of direct costs which is 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 confidence of the cost estimate for the RTR Project is considered to have an accuracy range estimate of 30%/-20%. The Project estimate was prepared in accordance with the recommended practice of the AACE International Cost Estimate Classification System.

d) The RTR Project estimate was prepared using Hydro One's current standard labour rates. These are consistent with labour rates used on other Hydro One-performed construction activities. Likewise, the material, equipment rentals and external contractor costs are based on standard rates used by Hydro One and calculated from experience garnered in past and ongoing construction projects for the categories listed above.

OEB STAFF INTERROGATORY #10

Reference:
Exhibit B, Tab 7, Schedule 1

Preamble:
Table 1 is an extract from the above reference.

Table 1: Extract from Exhibit B, Tab 7, Schedule 1, page 6

Table 2 - Costs of Comparable Line Projects

Project	RTR Project	WTTE Project	D6V/D7V Project	DxS Project
Scope	Reconductor four 230 kV lines	Reconductor four 115 kV lines	Reconductor two 230 kV lines	Reconductor two 115 kV lines
Length (km)	21.7	10.0	9.4	9.0
Circuit Length (km)[4]	70.8[5]	40.0	18.8	18.0
Project Surroundings	Urban	Urban	Mostly Rural	Mostly Urban
In-Service Date	Apr-2026	Nov-18	Dec-20	Dec-15
Years for escalation	-	7 yrs, 5 months	5 yrs, 4 months	10 yrs, 4 months
Total Project Cost (SM)[6]	**56.3**	**21.4**	**8.6**	**6.3**
Less: By-Pass ($M)	0.4	-	-	0.2
Less: OPGW Costs ($M)[7]	1.2	0.3	0.3	0.8
Total Project Costs Before Escalation ($M)	**54.7**	**21.1**	**8.3**	**5.3**
Add: Escalation Adjustment (2%/year)	-	3.3	0.9	1.2
Total Comparable Project Costs ($M)	**54.7**	**24.5**	**9.2**	**6.6**
Total Cost/Circuit km ($M)	**0.8**	**0.6**	**0.5**	**0.4**

At the above reference, Hydro One stated that the Richview by Trafalgar Reconductoring Project differs from the comparator reconductoring projects shown in Table 1 for two reasons. One reason provided was that tower reinforcement and some tower replacements are required for the Richview by Trafalgar Reconductoring Project whereas the comparator projects did not require tower reinforcement.

At Exhibit B, Tab 7, Schedule 1, p. 7, Hydro One states that the Richview by Trafalgar Reconductoring and WTTE projects "were also very similar in scope and included structural reinforcement and replacement of existing steel towers." At Exhibit C, Tab 1, Schedule 1 of Hydro One's WTTE application (EB-2016-0325), Hydro One describes the tower reinforcement and replacement work required to facilitate the project and for which it was seeking OEB approval.

At Exhibit B, Tab 7, Schedule 1, p. 9, Hydro One states that "no tower or tower replacements were required for the D6V/D7V Project". At Exhibit C, Tab 1, Schedule 1, p. 1 of Hydro One's D6V/D7V Project application (EB-2019-0165), Hydro One describes the various tower reinforcement work it planned to undertake to complete the project and for which it was seeking OEB approval.

Interrogatory:

a) In light of the above, please explain why Hydro One states that one of the two reasons for the higher cost of the Richview by Trafalgar Reconductoring Project is that the comparator projects did not require tower reinforcement.

b) Please confirm if the WTTE and D6V/D7V project costs shown in Table 1 are inclusive of tower reinforcement work.

c) With consideration to Hydro One's response to questions a) and b) above, please indicate if the only reason for the higher cost of the Richview by Trafalgar Reconductoring Project is that it involves work on four 230 kV circuits carried on two separate, and adjacent sets of towers, compared to the comparator projects where reconductoring was carried out on only a single set of towers. If applicable, please describe why it is appropriate that this single driver results in the Richview by Trafalgar Reconductoring Project costing between 33% and 60% higher than the WTTE and D6V/D7V project comparators, respectively, on a total cost per circuit km basis.

d) Hydro One states that the higher cost of the Richview by Trafalgar Reconductoring Project is partly attributable to the fact that it involves work on four 230 kV circuits carried on two separate, and adjacent sets of towers, compared to the comparator projects where reconductoring was carried out on only a single set of towers.

At Exhibit C, Tab 1, Schedule 1 of Hydro One's WTTE application (EB-2016-0325), Hydro One states "K1W/K3W and 8 K11W/K12W are each strung on two 2-circuit 115kV towers from Manby TS to Structure 4. From Structure 4 to Wiltshire TS all circuits are strung on 4-circuit 115kV towers, with the exception at Runnymede TS and St. Clair JCT." This statement indicates that while a portion of the WTTE project was carried out on a single set towers, another portion was carried out on separate and adjacent towers.

In light of the above, please clarify Hydro One's position that one of the two reasons for the higher cost of the Richview by Trafalgar Reconductoring Project is that the comparator projects only required work on a single set of towers.

e) Table 1 shows that the WTTE project involved the reconductoring of four 115 kV lines whereas the RTR project involves the reconductoring of four 230 kV lines. Please describe what, if any, cost differences between the RTR And WTTE projects are driven by the different conductor voltages.

f) With consideration to Hydro One's response to question c) and d) above, please provide an estimate of the difference in the Richview by Trafalgar Reconductoring Project's cost that Hydro One would attribute to completing work on four 230 kV circuits carried on two separate, and adjacent sets of towers, compared to the comparator projects where reconductoring was carried out on only a single set of towers. When responding, please describe the assumptions underpinning the estimate and why they are reasonable.

<u>Response:</u>

a) Hydro One would like to clarify that the tower reinforcement work described in Exhibit B, Tab 7, Schedule 1, page 4, is in the context of work required to upgrade the line security class design. The RTR Project requires towers to be replaced or reinforced to bring the towers up to the current security class design standards. In the three comparator projects provided in Table 1, no security class tower upgrade was included in the scope of work (as extracted in the question, above).

By upgrading a circuit's 'security class', Hydro One is describing when circuits, including tower structures, are reinforced and/or replaced to be able to withstand a severe weather event considered to have larger forces (or impacts) but usually is a weather event that is assumed to occur less often.

For illustrative purposes only, Hydro One is providing an example to help with the understanding of the concept of a ‘security class upgrade’.

For example, Hydro One may reinforce Circuit XYZ, which is a 230 kV circuit. The circuit could be located anywhere in Ontario, and appropriately designed for that geographical setting. The newly reinforced circuit (security class increase) will be designed to withstand a once-in-50 year storm, versus (for example) a one-in-10 year, or one-in-20 year weather event, that circuit XYZ is currently designed to withstand. This is an example of a ‘security class upgrade’.

b) Yes, the WTTE and D6V/D7V project costs in Table 1 (included above) are inclusive of tower reinforcement work.

c) No. As mentioned in Exhibit B, Tab 7, Schedule 1, Page 4, the RTR Project’s comparatively higher costs are largely due to two main drivers; (1) the need to work on two separate but adjacent sets of towers, and (2) the need to upgrade the line security class. Both these drivers result in increased construction effort and costs, as compared to the WTTE and D6V/D7V projects, which are described in more detail below:

Comparison to WTTE Project

The RTR Project has an increased construction effort when compared to the WTTE Project as it requires working on two separate but adjacent sets of towers, as opposed to the single set of towers for the WTTE project. This requires additional temporary access roads and doubles the number of crane and stringing pads for the reconductoring work. Furthermore, with the line security class upgrade, extra tower work is required resulting in a longer construction period, with more labour hours, greater equipment rental costs, and longer use of temporary facilities. It also increases the other associated costs of construction such as interest and overhead.

Other factors contributing to a higher per km costs for the RTR Project are the use of ACSS conductor and the higher voltage level of the lines. The ACSS conductor and related hardware are comparatively more costly than the conventional ACSR conductor and hardware used on the WTTE Project. The structural tower reinforcement work that would be required for larger 230 kV towers, is in comparison, greater compared to the tower reinforcement work required on the smaller 115kV towers that were associated with the WTTE Project circuits.

Comparison with the D6V/D7V Project

The rationale for the higher cost for the RTR Project, when compared to the D6V/D7V Project is analogous to the comparison provided above, for the WTTE Project. The D6V/D7V Project was a single double circuit line, and no security upgrade was carried out. In comparison, the RTR Project requires six new towers, structural steel reinforcement of all of the existing towers, of which there are two sets of towers adjacent to each other. Additionally on the RTR Project there is tower foundation reinforcement required to some of the existing towers that will remain in place.

Other factors contributing to the higher per km cost of the RTR Project is use of the ACSS-type conductor and the location of the RTR Project. The ACSS conductors and hardware are more costly, compared to the conventional ACSR-type conductor which was used on the D6V/D7V Project. The RTR Project is located in a dense urban setting with multiple road/train/water body crossings (such as; provincial highways, railways lines, GO Transit and Mississauga Bus Rapid Transit stations and the Credit River). Whereas the D6V/D7V Project is located in a rural setting absent many of the crossings mentioned above that the RTR Project must plan for and accommodate during construction. The multiple crossings will result in increased cost due to work required to establish a safe work area with Telescopic Boom Truck Cranes, temporary rider poles, and traffic controllers on each side of each crossing.

d) Hydro One has provided the main reasons for the higher per km cost of the RTR Project, when compared to the WTTE Project, above in part c). For clarification, a major cost element variance to that of the WTTE Project is related to the configuration of the design of these circuits and the number of towers that each circuit is carried by. The WTTE has only two spans of conductor carried on separate, and parallel, towers. These two spans of 115 kV conductor are carried on towers #1, #2 and #3 emanating from Manby TS, which is a distance of less than 0.5 km. The remainder of the 10km of 115 kV circuits on the WTTE Project, between Wiltshire TS to Manby TS, are strung on a 4-circuit single tower configuration between Tower #4 to Tower #48 (a total of 44 towers). Comparatively the RTR Project configuration carries the circuits on two sets of parallel towers (each carrying double circuits) the entire way from Richview TS to Trafalgar TS, a distance of approximately 21 km. This is one driver of the comparable per km project cost variance.

e) Please refer to the response in part c), above.

f) OEB staff have asked for a theoretical estimate for a project that does not exist and has not been contemplated by Hydro One. Estimation of theoretical projects, in the detail that OEB staff have requested, cannot be calculated in a matter of weeks with a realistic degree of accuracy. Each project forecast exercise takes considerable time and resources. Hydro One has explained the main drivers of the differences in the comparable projects table, however this question would appear to be reaching beyond reasonable expectations with which Hydro One has to provide a meaningful response.

Table 2, as presented in Exhibit B, Tab 7, Schedule 1 of the RTR Project Application, provides costs and information pertaining to the similarities and differences of those comparative projects, and are further supported by additional detailed information provided above in responses to parts a) through part d).

CITY OF MISSISSAUGA INTERROGATORY #1

Reference:

Exhibit E, Tab 1, Schedule 1
Land Matters - 1.0 Description of Land Rights

Preamble:

In Reference 1 above Hydro One Networks Inc. ("Hydro One") makes the following statement: "In addition, there is an easement over the City of Mississauga's property within this section measuring approximately 405m long."

Interrogatory:

a) Please provide a full copy of the registered easement over the City of Mississauga's (the "City") lands that are referred to as being 405m long;

b) In carrying out the proposed project work within the easement boundaries, does Hydro One intend to use any materials that may adversely affect the quality of the soil or groundwater or are otherwise defined as "substances" under the *Environmental Protection Act* of Ontario?

Response:

a) The City of Mississauga owns the land legally described as:
   - PCL BLOCK 279-1, SEC 43M573; BLK 279, PL 43M573, S/T TT76314 ASSIGNED BY TT103316 AND AMENDED BY TT119020; S/T 146945VS, 374315VS, TT41304, TT57259, TT66469; S/T, IF ENFORCEABLE, EXECUTION NOS 16237/91 & 54827/94; CITY OF MISSISSAUGA as in PIN 13138-0009 (LT)

For a redacted copy of the registered easements, please refer to Attachment A to this response. It includes a copy[1] of;k

1. instrument number TT41304, registered November 12, 1941, which is an easement for the R14/17T circuits; and
2. instrument number TT57259, registered November 25, 1949, which is an easement for the R19/21TH circuits.

b) For the proposed RTR Project, Hydro One will not be utilizing any materials that may adversely affect the quality of the soil or groundwater or are otherwise defined as “substances” under the *Environmental Protection Act* of Ontario.

[1] Hydro One has redacted any individual names and/or other personal information that is contained in Attachment 1. It is not in the public interest for these to be disclosed. Further, Hydro One has made an Application to the OEB, filed on the same day as the submission of these responses (i.e. October 8, 2021) asking for approval to maintain confidentiality of those details via the redactions made to Attachment 1 of evidence placed on the public record.

CITY OF MISSISSAUGA INTERROGATORY #2

Reference:
Exhibit E, Tab 1, Schedule 1
Land Matters - 1.0 Description of Land Rights

Preamble:
In Reference 1 above Hydro One makes the following statement: “Any temporary land rights required have not yet been identified but will be determined in advance of the Project’s construction start date. Hydro One will undertake their acquisition at the appropriate time. Temporary land rights required may include, but are not limited to, temporary access roads, temporary laydown areas and material storage areas.”

Interrogatory:
a) Please provide a time frame as to when Hydro One expects to develop its temporary land rights requirement(s), which may involve lands owned by the City.

Response:
a) Project activities on City of Mississauga land which Hydro One has a registered easement over are anticipated to commence in the summer of 2023.

If temporary rights are deemed necessary, Hydro One expects to develop its temporary land rights requirement(s) in Q4 2021.

It is expected that temporary road construction will be required to access Tower #39, for the R19/R21TH circuits, and Tower #44 for the R14/R17T circuits. Both Towers #39 and #44 are located with the City of Mississauga lands with construction anticipated to commence in the summer of 2023. Once Hydro One has performed any appropriate steel reinforcement of towers, and/or tower foundational reinforcement, the project work site will be restored back to its original condition. No other temporary land rights on City of Mississauga owned land are foreseen for the RTR Project at this time.

ENVIRONMENTAL DEFENCE INTERROGATORY #1

Reference:
Exhibit B-3-1, p. 8

Preamble:
The IESO project report dated July 12, 2021 states as follows:

Several transmission alternatives were considered that can provide increases in the FETT capacity.

Those options were narrowed down to two options that meet the following two criteria:

- Can be in-service before the summer 2026.
- Provide an increase in transfer capability of at least 2,250 MW in 2026 assuming all transmission elements in service.

Interrogatory:
a) Please confirm that the two criteria are that the project: (i) can be in-service before the summer 2026; and (ii) provide an increase in transfer capability of at least 2,250 MW in 2026 assuming all transmission elements in service.

Response:
This response has been provided by the IESO.

a) The IESO confirms these were the two screening criteria used to narrow down transmission alternatives to those for detailed alternative comparison analysis. In assessing these criteria, the IESO required a high degree of confidence that an alternative would provide sufficient transfer capability and be in-service before the summer of 2026 to meet the reliability need.

ENVIRONMENTAL DEFENCE INTERROGATORY #2

Reference:
Exhibit B-3-1, p. 8

Preamble:
"At the development phase of the project, numerous conductors were considered for upgrading the Trafalgar TS x Richview TS lines. It was concluded that the use of 1433 kcmil ACSS would provide the required planning summer long term emergency (LTE) rating of 2000 A. It is a high-temperature compact conductor that allows the required rating without involving significant tower modifications. The existing line includes 795 kcmil ACSR and 1307 kcmil ACSR conductors. The reduction in the resistance, hence reduction in line losses, will be about 44% for the sections with 795 kcmil ACSR and about 8% for the sections with 1307 kcmil ACSR."

Interrogatory:

a) Does Hydro One take the position that it was unable to seek OEB approval for a larger conductor than 1433 kcmil ACSS 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 1433 kcmil ACSS)? Please provide Hydro One's view and ask for 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, Hydro One does **not** take this 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

Please refer to Exhibit I, Tab 3, Schedule 6, part b), for the IESO's view

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 provided the IESO with a list of 230kV conductors that Hydro One currently utilizes on the transmission system and their associated ampacities. The discussions between Hydro One and the IESO resulted in the recommendation to use the 1,433 kcmil ACSS conductor because the Hydro One standard ACSR conductors are not able to meet the ampacity rating requested by the IESO of 2,000A (please see Table 1, below, that illustrates this conclusion).

Hydro One and IESO did not discuss the possibility of upsizing the 1,433 kcmil ACSS conductor to cost effectively reduce transmission losses, because any kcmil ACSS conductor greater than 1,433kcmil would require at a minimum, further tower reinforcement/modifications, and/or additional towers to provide appropriate overhead line clearances. Therefore Hydro One considered the use of a larger size ACSS conductor and ruled it out as uneconomical. Given this conclusion it was not discussed as a viable option with the IESO.

Please refer to Table 1 below for more information regarding the conductor types considered and their ampacity/size characteristics.

Table 1 - Conductor Ampacity Comparison - by Size and Type

Size (kcmil)	1443	1780	1433	1730
Type	ACSR	ACSR	ACSS	ACSS
Ampacity (A)	1530	1720	2000	2245
Conductor Meets the IESO Ampacity Requirement?	No	No	Yes	Yes

Further information regarding the additional cost and scope of work required to accommodate the larger 1730 kcmil ACSS sized conductor is provided in Exhibit I, Tab 3, Schedule 3. Additionally, at the request of Environmental Defence, at Exhibit I, Tab 3, Schedule 4, an NPV was performed on the incremental project costs for the larger conductor (1730 kcmil ACSS) that is capable of providing the ampacity rating required by the IESO.

ENVIRONMENTAL DEFENCE INTERROGATORY #3

Reference:

Exhibit B-3-1, p. 8

Preamble:

"Several transmission alternatives were considered that can provide increases in the FETT capacity.

Those options were narrowed down to two options that meet the following two criteria:

- Can be in-service before the summer 2026.
- Provide an increase in transfer capability of at least 2,250 MW in 2026 assuming all transmission elements in service.

At the development phase of the project, numerous conductors were considered for upgrading the Trafalgar TS x Richview TS lines. It was concluded that the use of 1433 kcmil ACSS would provide the required planning summer long term emergency (LTE) rating of 2000 A. It is a high-temperature compact conductor that allows the required rating without involving significant tower modifications. The existing line includes 795 kcmil ACSR and 1307 kcmil ACSR conductors. The reduction in the resistance, hence reduction in line losses, will be about 44% for the sections with 795 kcmil ACSR and about 8% for the sections with 1307 kcmil ACSR."

Interrogatory:

a) Please provide a list of the type and size of conductors that would also result in an increase in transfer capability of at least 2,250 MW in 2026 assuming all transmission elements in service (aside from 1433 kcmil ACSS). Presumably this will include a variety of larger conductors.

b) Please estimate the cost of the project based on the various potential conductors that would meet the required transfer capability (at least 2,250 MW assuming all transmission elements in service) and include those estimates in the following table:

Conductor Alternatives – Capital Cost Comparison	
	Total Capital Cost
Conductor 1: 1433 kcmil ACSS	$56.3 million
Conductor 2:	
…	
Conductor n	

c) 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 transfer capability (at least 2,250 MW assuming all transmission elements in service) 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: 1433 kcmil ACSS	X kwh
Conductor 2	Y kwh
…	…
Conductor n	

d) 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 (c) 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: 1433 kcmil ACSS	$X
Conductor 2	$Y
…	…
Conductor n	

e) Please estimate annual transmission losses that would result from the various potential conductors that would meet the required transfer capability (at least 2,250 MW assuming all transmission elements in service) 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: 1433 kcmil ACSS	X kwh
Conductor 2	Y kwh
…	…
Conductor n	

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

Conductor Alternatives – Transmission Loss Comparison – 40 Years			
	Estimated Annual Transmission Losses		
	Year 1	…	Year 40
Conductor 1: 1433 kcmil ACSS	X kwh		
Conductor 2	Y kwh		
…	…		
Conductor n			

g) Please estimate the value of transmission losses listed in (f) based on the avoided cost figures published by the IESO as part of its latest Annual Planning Outlook and provide the results in the following table:

Conductor Alternatives – Transmission Loss Value – 40 Years			
	Estimated Annual Transmission Losses Value		
	Year 1	…	Year 40
Conductor 1: 1433 kcmil ACSS	$X	…	
Conductor 2	…		
…			
Conductor n			

h) 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 transfer capability (at least 2,250 MW assuming all transmission elements in service). Please include a function to determine the losses based on the load (MW).

i) 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 for every hour in the year.

Response:

a) Any ACSS conductor with a size larger than 1433 kcmil would result in a capacity increase of at least 2,250 MW. However, the conductor properties need to be carefully evaluated to ensure that apart from the ampacity requirements, the conductor has the necessary strength to be strung on the existing towers (otherwise considerable addition costs would be required to accommodate a heavier conductor on the towers). For this reason, there were only two conductor sizes considered. For comparative purposes, Hydro One has provided information pertaining to the 1730 kcmil ACSS conductor, because this kcmil conductor is the closest diameter size to the Hydro One 1780 kcmil ACSR which it uses in standard applications[1].

Hydro One has only considered the ACSS-type conductors for this project because the ACSR-type conductors of a specification (i.e. size) that would be required to meet the IESO capacity (of 2250MW) would require Hydro One to perform extensive tower modifications/reinforcement and/or rebuilding new towers to accommodate the added weight of higher capacity ACSR conductor required.

b) As mentioned in part a) above, Hydro One has only considered the 1730 kcmil ACSS conductor for comparative purposes. Costs for the project that would utilize the 1730 kcmil conductor are provided below in Table A. The higher project cost is due to the additional modifications that would be required to the existing towers, and/or additional new towers beyond that proposed for the 1433 kcmil RTR Project.[2] The larger and heavier 1730 kcmil conductor would necessitate the construction of additional new

[1] The reason Hydro One has not provided 1780 kcmil ACSR information, is because the ACSR-type conductor in that size does not meet the ampacity requirements,

[2] Please refer to Exhibit I, Tab 3, Schedule 5 for a cost comparison between the level of tower-related costs required for each of the two alternatives.

towers along the circuit pathway, and the various additional new accessory costs of connecting the conductor, in addition to increased labour and equipment effort to support an expanded the scope (for example, additional temporary access roads and crane pads for the new towers, combined with greater inherent interest, overhead and potential increased contingency), resulting from the cost of a the larger and heavier 1730 kcmil reconductoring option. For these cost-inhibitive reasons any larger capacity conductor/s sizes beyond the 1730 kcmil were not assessed. Hydro One is providing the below information in the form requested by Environmental Defence for the proposed Project conductor size/type and the single alternative. Further options are not considered feasible, or appropriate.

Table A below provides the cost comparison:

Table A

Conductor Alternatives – Capital Cost Comparison	
	Total Capital Cost
Conductor 1: 1433 kcmil ACSS	$60.9 million
Conductor 2: 1730 kcmil ACSS	$79.0 million

c) The MWh loss for the 1433 kcmil ACSS conductor and the 1730 kcmil ACSS conductor assuming the maximum forecast flow as occurring 24/7/365 are given below in Table B:

Table B

Conductor Alternatives – Annual Transmission Loss Comparison for Screening	
	Estimated Transmission Loss
Conductor 1: 1433 kcmil ACSS	91179 MWh (peak losses = 10.41 MW)
Conductor 2: 1730 kcmil ACSS	76421 MWh (peak losses = 8.72 MW)

d) The cost of the transmission losses assuming peak flows 24/7/365 based on $120/MWh are provided below in Table C:

Table C

Conductor Alternatives – Annual Transmission Loss Value (for Screening Only)	
	Estimated Transmission Losses Value
Conductor 1: 1433 kcmil ACSS	91179 MWh @ $120MWh = $10,941,495
Conductor 2: 1730 kcmil ACSS	76421 MWh @ $120MWh = $9,170,474

e) The annual losses based on 2020 Flows are given in Table D below:

Table D

Conductor Alternatives – Annual Transmission Loss Comparison	
	Estimated Transmission Losses
Conductor 1: 1433 kcmil ACSS	3908.6 MWh
Conductor 2: 1730 kcmil ACSS	3275.9 MWh

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

g) The estimated value of transmission losses calculated as requested in (f) are also provided in Table E below. These are based on the avoided cost figures published by the IESO as part of its latest Annual Planning Outlook (APO[3]). The APO contains values only to 2040. For the remaining years Hydro One has held the 2040 constant going forward.

[3] 2020 IESO Annual Planning Outlook – Link to Report
https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

1 **Table E - Conductor Alternatives – Transmission Loss and Value Comparison[4] – 40 Years**

No.	Losses (MWh)		IESO Avoided Cost (2020$/MWH)	Avoided Cost Based on IESO APO		
	1433 kcmil ACSS	1730 kcmil ACSS		1433 kcmil ACSS	1730 kcmil ACSS	Difference
0	3908.6	3275.9	$23	$89,897.31	$75,346.30	$14,551.01
1	4064.9	3407.0	$23	$93,225.46	$78,135.75	$15,089.71
2	4227.5	3543.2	$23	$97,165.05	$81,437.67	$15,727.38
3	4396.6	3685.0	$29	$125,952.02	$105,565.11	$20,386.91
4	4572.5	3832.4	$27	$125,394.07	$105,097.47	$20,296.60
5	4755.4	3985.7	$28	$135,356.56	$113,447.40	$21,909.15
6	4945.6	4145.1	$33	$163,088.04	$136,690.20	$26,397.84
7	5143.4	4310.9	$32	$166,452.43	$139,510.02	$26,942.41
8	5349.2	4483.3	$33	$176,766.21	$148,154.39	$28,611.83
9	5563.1	4662.7	$33	$183,392.93	$153,708.48	$29,684.44
10	5785.7	4849.2	$36	$209,642.28	$175,709.05	$33,933.23
11	6017.1	5043.1	$36	$214,476.74	$179,760.99	$34,715.75
12	6257.8	5244.9	$34	$214,819.69	$180,048.43	$34,771.26
13	6508.1	5454.7	$35	$226,081.47	$189,487.36	$36,594.12
14	6768.4	5672.8	$34	$232,353.15	$194,743.88	$37,609.27
15	7039.1	5899.8	$37	$262,272.83	$219,820.69	$42,452.14
16	7320.7	6135.7	$38	$280,517.58	$235,112.29	$45,405.28
17	7613.5	6381.2	$39	$294,773.02	$247,060.32	$47,712.71
18	7918.1	6636.4	$41	$325,954.56	$273,194.73	$52,759.83
19	8234.8	6901.9	$44	$361,167.47	$302,707.99	$58,459.48
20	8564.2	7178.0	$47	$399,016.01	$334,430.27	$64,585.74
21	8906.7	7465.1	$47	$414,976.65	$347,807.48	$67,169.17
22	9263.0	7763.7	$47	$431,575.71	$361,719.78	$69,855.94
23	9633.5	8074.2	$47	$448,838.74	$376,188.57	$72,650.17
24	10018.9	8397.2	$47	$466,792.29	$391,236.11	$75,556.18
25	10419.6	8733.1	$47	$485,463.98	$406,885.55	$78,578.43
26	10836.4	9082.4	$47	$504,882.54	$423,160.98	$81,721.56
27	11269.9	9445.7	$47	$525,077.84	$440,087.42	$84,990.43
28	11720.7	9823.5	$47	$546,080.96	$457,690.91	$88,390.04
29	12189.5	10216.5	$47	$567,924.19	$475,998.55	$91,925.65
30	12677.1	10625.1	$47	$590,641.16	$495,038.49	$95,602.67
31	13184.2	11050.1	$47	$614,266.81	$514,840.03	$99,426.78
32	13711.5	11492.1	$47	$638,837.48	$535,433.63	$103,403.85
33	14260.0	11951.8	$47	$664,390.98	$556,850.98	$107,540.00
34	14830.4	12429.9	$47	$690,966.62	$579,125.02	$111,841.60
35	15423.6	12927.1	$47	$718,605.28	$602,290.02	$116,315.27
36	16040.5	13444.2	$47	$747,349.50	$626,381.62	$120,967.88
37	16682.2	13981.9	$47	$777,243.48	$651,436.88	$125,806.59
38	17349.5	14541.2	$47	$808,333.21	$677,494.36	$130,838.86
39	18043.4	15122.9	$47	$840,666.54	$704,594.13	$136,072.41
40	18765.2	15727.8	$47	$874,293.20	$732,777.90	$141,515.31

[4] Assumes load increase growth of 2% per annum.

h) 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;

$$I = \frac{MW}{\sqrt{3} * Voltage}$$

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

i) Please refer to Attachment A to this response for a live model in MS Excel format.

ENVIRONMENTAL DEFENCE INTERROGATORY #4

Reference:
Exhibit B-3-1, p. 8

Preamble:
"Several transmission alternatives were considered that can provide increases in the FETT capacity.

Those options were narrowed down to two options that meet the following two criteria:

- Can be in-service before the summer 2026.
- Provide an increase in transfer capability of at least 2,250 MW in 2026 assuming all transmission elements in service.

At the development phase of the project, numerous conductors were considered for upgrading the Trafalgar TS x Richview TS lines. It was concluded that the use of 1433 kcmil ACSS would provide the required planning summer long term emergency (LTE) rating of 2000 A. It is a high-temperature compact conductor that allows the required rating without involving significant tower modifications. The existing line includes 795 kcmil ACSR and 1307 kcmil ACSR conductors. The reduction in the resistance, hence reduction in line losses, will be about 44% for the sections with 795 kcmil ACSR and about 8% for the sections with 1307 kcmil ACSR."

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 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 1433 kcmil ACSS conductor option was the preferred option on a cost-benefit basis for

[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.

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 Environment Defence, a 40-year net present value (NPV) analysis that compared the two discussed alternatives, a) 1433 kcmil ACSS and b) 1730 kcmil ACSS, to reconductor the Trafalgar TS x Richview TS circuits. The incremental NPV result of selecting the larger 1730 kcmil ACSS conductor, compared to the preferred option over a 40 year time horizon, yields an incremental negative cost (i.e. additional cost to ratepayers) of $13.6M[2] using the IESO-provided HOEP, or an incremental negative cost of $10.2M[3] using a $120/MWH assumption. Both scenario calculations are provided in Tables 1 through 4 below. This NPV analysis, ultimately shows that the additional incremental cost of the larger 1730 kcmil ACSS 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;

> *"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]*

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[2] As per the result of Table 1 below (based on HOEP price provided by the IESO).
[3] As per the result of Table 3 below (based on the energy cost of $120/MWH).
[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
[6] EB-2020-0265, Decision and Order Page – April 22, 2021, pgs., 14,15

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. In terms of the incremental cost NPV analysis – between two options: 1433 kcmil ACSS vs. 1730 kcmil ACSS conductors, Tables 1 and 2 uses the Hourly Ontario Energy Price (HOEP), and Tables 3 and 4 use an energy cost of $120/MWH. In terms of the results provided in Tables 1 through 4, below, the following assumptions were used in the NPV analysis requested by ED:

1. The cost for the 1433 kcmil ACSS conductor is $60.9M vs. the cost for 1730 kcmil ACSS conductor is $79.0M, and additional incremental cost of $18.1M.
2. There are no incremental revenues and/or operating and maintenance costs for the larger 1730 kcmil ACSS conductor size, compared to the preferred option.
3. Hydro One calculated two incremental cost analysis NPV line loss assessments as described below: as follows;
    a. The first assessment is based on Hourly Ontario Energy Price (HOEP), as provided by the IESO, and is not subject to inflation.[8] The results are shown in Table 1 and 2.
    b. The second assessment is based on the energy cost of $120/MWH[9] and the results shown in Tables 3 and 4.
4. The discount factor of 5.31% is derived from information contained in Hydro One's OEB-approved Draft Rate Order for cost of capital parameters[10].
5. 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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[7] EB-2019-0082 – OEB's Decision and Order, April 23, 2020, pgs. 58,59.
[8] If Ontario CPI escalation rates are considered, the NPV analysis of the 1730 kcmil ACSS conductor option would result in a change to negative $12.6M (i.e. incremental costs not recovered).
[9] Hydro One used $120/MWH HOEP to be consistent with the value ED asked to be used for the HOEP in Exhibit I, Tab 3, Schedule 3, part d).
[10] EB-2019-0082 - Hydro One Networks' 2020-2022 Transmission Revenue Requirement, Draft Rate Order, May 28, 2020 – Exhibit 1.4 page 1.
[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: 1433 kcmil ACSS vs. 1730 kcmil ACSS conductors, Page 1

Incremental analysis comparing two options: 1433 vs. 1730 kcmil ACSS conductors (in $k)
For 40 Years Ended December 31st, 2065

	Total	Period 0	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
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 to 1730 kcmil	-18,100	-18,100	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	4,728	0	384	353	325	299	275	253	233	214	197	181	167	153	141	130	119	110	101	93	86	79	72
Incremental Line Loss Savings	4,757	0	62	61	62	63	66	71	70	70	76	78	86	95	101	115	110	109	112	115	117	120	123
Net Incremental Impact to Ratepayers	**-8,614**	**-18,100**	**446**	**414**	**387**	**362**	**341**	**324**	**302**	**284**	**272**	**259**	**252**	**248**	**242**	**245**	**230**	**219**	**213**	**208**	**203**	**199**	**195**
Discount Factor		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		-18,100	423	373	332	294	263	238	211	188	171	155	143	133	124	119	106	96	88	82	76	71	66
Cumulative Net Present Value for the upsize to 1730 kcmil	**-13,596**	**-18,100**	**-17,677**	**-17,304**	**-16,972**	**-16,678**	**-16,415**	**-16,177**	**-15,966**	**-15,778**	**-15,607**	**-15,453**	**-15,310**	**-15,176**	**-15,053**	**-14,934**	**-14,828**	**-14,733**	**-14,644**	**-14,562**	**-14,486**	**-14,416**	**-14,350**

Note: This Table uses the Hourly Ontario Energy Price (HOEP)

Table 2 - Incremental Cost NPV Analysis – Between Two Options: 1433 kcmil ACSS vs. 1730 kcmil ACSS conductors, Page 2

Incremental analysis comparing two options: 1433 vs. 1730 kcmil ACSS conductors (in $k)
For 40 Years Ended December 31st, 2065

	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	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 to 1730 kcmil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield	67	61	56	52	48	44	40	37	34	31	29	27	24	23	21	19	18	16	15	103
Incremental Line Loss Savings	126	129	132	134	137	140	143	146	148	151	154	157	160	163	165	168	171	174	177	0
Net Incremental Impact to Ratepayers	**193**	**190**	**188**	**186**	**185**	**184**	**183**	**183**	**183**	**183**	**183**	**184**	**184**	**185**	**186**	**187**	**189**	**190**	**192**	**103**
Discount Factor	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	62	58	54	51	48	46	43	41	39	37	35	33	32	30	29	28	26	25	24	13
Cumulative Net Present Value for the upsize to 1730 kcmil	**-14,288**	**-14,230**	**-14,176**	**-14,125**	**-14,077**	**-14,031**	**-13,988**	**-13,947**	**-13,909**	**-13,872**	**-13,837**	**-13,803**	**-13,772**	**-13,741**	**-13,713**	**-13,685**	**-13,658**	**-13,633**	**-13,609**	**-13,596**

Note: Table 2 uses the Hourly Ontario Energy Price (HOEP)

Table 3 - Incremental Cost NPV Analysis – Between Two Options: 1433 kcmil ACSS vs. 1730 kcmil ACSS conductors, Page 3

Incremental analysis comparing two options: 1433 vs. 1730 kcmil ACSS conductors (in $k)
For 40 Years Ended December 31st, 2065

	Total	Period 0	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046
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 to 1730 kcmil	-18,100	-18,100	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	4,728	0	384	353	325	299	275	253	233	214	197	181	167	153	141	130	119	110	101	93	86	79	72
Incremental Line Loss Savings	12,835	0	280	267	262	262	251	255	257	253	281	291	308	332	340	378	352	339	339	339	339	339	339
Net Incremental Impact to Ratepayers	**-537**	**-18,100**	**664**	**620**	**586**	**561**	**525**	**508**	**489**	**467**	**478**	**472**	**474**	**485**	**481**	**508**	**471**	**449**	**440**	**432**	**424**	**417**	**411**
Discount Factor		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		-18,100	631	559	502	456	406	373	341	309	300	282	269	261	246	246	217	196	183	170	159	148	139
Cumulative Net Present Value for the upsize to 1730 kcmil	**-10,194**	**-18,100**	**-17,469**	**-16,911**	**-16,408**	**-15,953**	**-15,547**	**-15,174**	**-14,834**	**-14,525**	**-14,225**	**-13,944**	**-13,675**	**-13,414**	**-13,169**	**-12,922**	**-12,705**	**-12,509**	**-12,327**	**-12,156**	**-11,998**	**-11,849**	**-11,711**

Note: Table 3 uses the energy cost of $120/MWH

Table 4 - Incremental Cost NPV Analysis – Between Two Options: 1433 kcmil ACSS vs. 1730 kcmil ACSS conductors, Page 1

Incremental analysis comparing two options: 1433 vs. 1730 kcmil ACSS conductors (in $k)
For 40 Years Ended December 31st, 2065

	2047	2048	2049	2050	2051	2052	2053	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	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 to 1730 kcmil	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Incremental CCA Tax Shield	67	61	56	52	48	44	40	37	34	31	29	27	24	23	21	19	18	16	15	103
Incremental Line Loss Savings	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	339	0
Net Incremental Impact to Ratepayers	**405**	**400**	**395**	**391**	**386**	**383**	**379**	**376**	**373**	**370**	**368**	**365**	**363**	**361**	**359**	**358**	**356**	**355**	**354**	**103**
Discount Factor	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	130	122	114	107	101	95	89	84	79	74	70	66	63	59	56	53	50	47	45	13
Cumulative Net Present Value for the upsize to 1730 kcmil	**-11,581**	**-11,459**	**-11,345**	**-11,238**	**-11,137**	**-11,042**	**-10,953**	**-10,869**	**-10,790**	**-10,716**	**-10,645**	**-10,579**	**-10,517**	**-10,457**	**-10,402**	**-10,349**	**-10,299**	**-10,252**	**-10,207**	**-10,194**

Note: Table 4 uses the energy cost of $120/MWH

ENVIRONMENTAL DEFENCE INTERROGATORY #5

Reference:

Reference: Exhibit B-07-01, p. 10

Preamble:

"[T]he RTR Project requires tower modifications to accommodate the new heavier conductor. This is expected to include tower reinforcement, including localized steel member replacement and foundational upgrades for increased loading conditions. Additionally, six towers along the route have been identified as needing full replacement."

Interrogatory:

a) Please describe and estimate the cost of the tower modifications that would be required for the various potential conductors that would meet the required transfer capability (at least 2,250 MW assuming all transmission elements in service) and include those in the following table:

Conductor Alternatives – Tower Modification Comparisons		
	Description of Tower Modifications	Estimated Cost of Tower Modifications
Conductor 1: 1433 kcmil ACSS		
Conductor 2		
…		
Conductor n		

Response:

Table A, below, provides the tower modification description and cost comparatives (less removal costs) between the preferred alternative for the RTR Project (i.e. 1433 kcmil ACSS conductor), vs, a 1730 kcmil ACSS project design/scope option[1].

[1] Refer to Exhibit I, Tab 1, Schedule 3 for the rationale and total project cost comparison underpinning why Hydro One has provided only two conductor/tower project options.

Table A - Conductor Alternatives – Tower Modification Comparisons

	Description of Tower Modifications	**Estimated Cost of Tower Modifications ($M)**
Conductor 1: Proposed RTR Project **1433 kcmil ACSS**	• Tower structural steel reinforcement • Temporary crane pads and associated access roads to the crane pads to support steel replacement • Existing concrete foundation modifications • Existing tower mounding • Six tower replacements	$16.7
Alternative: Conductor 2: **1730 kcmil ACSS**	• Additional tower structural steel reinforcement compared to Conductor 1. • Temporary crane pads and associated access roads to the crane pads to support steel replacement • Existing concrete foundation modifications • Existing tower mounding • Ten tower replacements	$33.3

ENVIRONMENTAL DEFENCE INTERROGATORY #6

Reference:
Exhibit B-3-1, p. 8

Interrogatory:
a) Please provide the capacity the various potential conductors that would meet the required transfer capability (at least 2,250 MW assuming all transmission elements in service) and include those estimates in the following table:

Conductor Alternatives – Capacity Comparison	
	Capacity
Conductor 1: 1433 kcmil ACSS	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:
The following response has been provided by the IESO.

a)

Table 1 - Conductor Alternatives – Capacity Comparison

	Capacity
Conductor 1: 1433 kcmil ACSS	2,250 MW
Conductor 2: 1730 kcmil ACSS	(See Note 1 below)

Note 1 - The use of 1730 kcmil ACSS would provide a higher FETT transfer capability than that with 1433 kcmil ACSS. The IESO has not carried out the system studies to determine the higher FETT transfer capability. The purpose of the Richview x Trafalgar line upgrade project is to meet the security requirement. The use of 1433 kcmil ACSS will meet this need. The use of 1730 kcmil ACSS would cost approximately $18M more and, based on the information the IESO has, it would not recommend the use of 1730 kcmil ACSS.

b) The future value of capacity is dependent on the outcome of supply procurement decisions. It is inappropriate for the IESO to speculate about the design and outcome to its future procurements ahead of those procurements being designed, engaged upon with stakeholders, and implemented. Information regarding future IESO procurements would be released in accordance with the implementation of those procurements.

ENVIRONMENTAL DEFENCE INTERROGATORY #7

Reference:
Exhibit B-07-1, p. 1

Interrogatory:
a) Please provide a breakdown of the project cost table (Table 1 – Project Cost) divided into work relating to tower modification and other work.

Response:
The project cost breakdown for work relating to tower modifications and other associated work is presented below in Table A.

Table A - Tower Modifications – Cost Breakdown

	Estimated Cost ($M)	**Tower Modification Costs ($M)**	**Other Costs ($M)**
Materials	13.6	4.2	9.4
Labour	17.0	3.9	13.1
Equipment Rental & Contractor Costs	13.9	5.0	8.9
Sundry	1.9	0.6	1.3
Contingencies	2.7	0.8	1.9
Overhead [1]	4.6	1.4	3.2
Capitalized Interest [2]	2.3	0.7	1.6
Real Estate [3]	0.2	0.1	0.1
TOTAL PROJECT WORK	**$ 56.3**	**$16.7**	**$39.6**

[1] Overhead Costs allocated to the project are for corporate services costs. These costs are charged to capital projects through a standard overhead capitalization rate. As such they are considered "Indirect Overheads".
[2] Capitalized Interest is calculated using the Board's approved interest rate methodology (EB-2016-0160) to the Project's forecast monthly cash flow and carrying forward closing balances from the preceding month.
[3] Real Estate costs for the RTR Project is to acquire crossing permits to string conductors over railways, roads and waterways, as appropriate.

ENVIRONMENTAL DEFENCE INTERROGATORY #8

Reference:
Exhibit B-03-01-03, p. 8

Preamble:
"Greater flexibility in where supply resources are located is expected to provide greater competition amongst those supply resources and ultimately lead to ratepayer savings."

Interrogatory:
a) Please provide an estimate of the value of the ratepayer savings described above. Please do so on a best-efforts basis. An order-of-magnitude estimate is sufficient. Please make and state any assumptions as necessary. If necessary, please ask the IESO for its estimate.

b) Please provide a map or maps showing: (i) the approximate area in which supply resources would need to be procured if the project is not built; and (ii) the approximate area in which supply resources can be procured if the project is built. If necessary, please ask the IESO for this information.

c) Please describe the kinds and magnitude of supply resources that this project will potentially enable. For example:
   a. Is this likely to enable more wind, storage, or solar assets from western Ontario, and if yes, how much of each?
   b. Is this likely to enable more imports, and if yes, how much from each neighbour?
   c. Is this likely to enable generation from gas fired generation, and if yes, how much?

Response:
The following response has been provided by the IESO.

a) Please refer to the response Exhibit I, Tab 1, Schedule 2.

b) (i) The area considered to be east of FETT includes the areas shown east of the electrical boundary in Map1, below.

Map 1 – Map of the Area East of FETT

b) (ii) If the RTR Project is implemented resources could be sited across the province.

c) The proposed upgrade to the FETT interface would allow any form of new and existing resources located west of the FETT interface to support the need east of the FETT interface by an additional ~2,000 MW.

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #1

Reference:

Exhibit B-3-1, Attachment 3

Preamble:

In the IESO revenue requirement (EB-2020-0230) the IESO expects to complete the Market Renewal Program (MRP) by 2023. Among other market design changes, the IESO is proposing to change the current two-schedule system to a single schedule system for real-time operation. The result will be the adoption of Locational Marginal Pricing (LMP) in Ontario. The *MRP Energy Stream Business Case* dated October 22, 2019 outlines that the incentives from LMP for siting and operating generation efficiently in constrained zones are a primary benefit of MRP.

Transmission congestion on the Flow East Towards Toronto (FETT) interface would reasonably be expected to increase LMP prices east of FETT.

Interrogatory:

a) Please provide any estimates of congestion cost for do-nothing scenario (i.e., the proposed project is not developed) on an annual basis. Please provided a detailed explanation of the assumptions and methodology in preparing congestion costs. Please provide all data sets, financial models, and sources of information used in the analysis.

b) Please provide the IESO's estimate for annual and monthly average LMP for major nodes and/or zones east of FETT if the project does not proceed. If the IESO has not estimated LMPs east of FETT, please provide an estimate of congestion costs on the FETT interface or provide reasoning why an estimate was not prepared.

c) Please provide the IESO's estimate for annual and monthly average LMP for major nodes and/or zones east of FETT for all proposed alternatives including the preferred option. If the IESO has not estimated LMPs east of FETT, please provide an estimate of congestion costs on the FETT interface or provide reasoning why an estimate was not prepared.

d) Please provide all analyses that compares the economics of the preferred option versus do nothing that include congestion costs on the FETT interface. For example, the preferred project cost is estimated by Hydro One to be $60.9 million dollars (Exhibit B-1-1). Please show the amount of congestion cost savings expected for the project costs. Please provide all data sheets, financial models, and sources of information used in the analysis.

e) Please describe how LMP would be incorporated into the procurement mechanisms. If LMP was not incorporated, please provide an explanation why LMP was ignored with reference to qualitative and quantitative benefits set out in the IESO's *MRP Energy Stream Benefits Case*.

Response:

The following response has been provided by the IESO.

a) A do-nothing scenario is not an acceptable option for 2026 when Pickering GS retires. The proposed reconductoring project is required to meet North American reliability standards requirements as set out in NERC TPL-001 and NPCC Directory #1. The west-to-east transfer capability of the FETT transmission interface plus the capacity from resources located east of FETT needs to be sufficient to supply the demand east of FETT in manner meeting the above criteria. If the proposed reconductoring project was not developed, the IESO would need to acquire approximately 2,000 MW of new resources located east of FETT by 2026 to be compliant with its reliability obligations. The IESO has concluded that successfully acquiring approximately 2,000 MW of new resources east of FETT by 2026 represents an unacceptable risk. This RTR Project is being recommended to address this reliability risk. It is not being recommended to reduce congestion costs and, hence, calculating locational marginal prices and congestion costs isn't necessary nor possible before the go-live of Market Renewal in November 2023.

b) Please see response to question (a).

c) Please see response to question (a).

d) Please see response to question (a).

e) Please see response to question (a).

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #2

Reference:

Exhibit B-3-1, Attachment 3

Preamble:

Section 3.2 of the IESO's June 12, 2021 report entitled *Trafalgar TS x Richview TS 230 kV line upgrade: Need and Selection of the Preferred Plan* (the "**Report**") states "[w]hen acquiring new supply to meet the provincial need for capacity, it may be possible to run the capacity auction and resource procurements with a requirement to locate approximately 2,000 MW east of the FETT interface by 2026. The IESO is aware of some interest in developing new supply east of the interface and imports from Quebec and New York [*sic.*] could provide some of that supply; however, the amount we're aware of isn't enough to meet the approximately 2,000 MW need and/or it is unclear whether or not it can be developed/acquired in 2026. Hence, there is significant uncertainty and risk in being able to obtain a sufficient amount of new supply resources east of FETT by 2026."

Interrogatory:

a) Please provide a detailed description of the IESO's outreach strategy to supply resource developers and existing operators as part of its system need assessment and alternative solution options. If the IESO did not engage directly with resource developers, please provide a detailed explanation of why and how the IESO reached its conclusion of insufficient interest?

b) Please provide a list of entities and market participants engaged by the IESO in determining interest in developing new supply resources east of the interface. If the IESO cannot provide that information, please provide a count of IESO's meetings/correspondence with resource operators and resource developers.

c) Please provide a summary of interest in developing new supply east of the FETT interface by:
   i. Resource type (e.g., gas-fired generation, solar generation, wind generation, energy storage, imports, hydroelectric generation, nuclear generation, demand response)
   ii. Expansions of existing facilities including uprates and new capacity expansions

iii. Magnitude of resource development capabilities (i.e., capacity and annual energy production)

d) Please provide details of all revenue mechanisms considered by the IESO in its assessment of alternative solutions. Please clearly describe and identify the procurement and revenue mechanisms and models used by the IESO to assess the cost and uncertainty associated with alternative solutions. For example, responses should identify any assumptions and details relating to revenues assumed by the IESO to be available through market mechanisms (e.g., capacity, energy, ancillary services) as well as through out-of-market mechanisms (e.g., out-of-market payments, programs, contracts).

e) Did the IESO include assumptions relating to the cost and availability of capital (debt and equity) when exploring and modeling procurement mechanisms and revenue models that could be used to compensate proponents capable of providing alternative solutions? If so, please identify the source and basis of inputs and assumptions used to determine availability and cost of capital. If not, please identify reasons why this analysis was not undertaken when considering the viability of alternative solutions.

f) Did the IESO explore continued operation of Pickering NGS beyond the current end-of-life of 2024/2025?

g) Please provide a detailed development timeline the IESO used in its assumption that new capacity could not be developed by 2026.

h) Please provide all IESO records (including draft reports, notes, emails, internal and external meeting materials, etc.) of its consideration and/or evaluation of existing and possible new capacity supply resources east of the FETT interface.

i) Please provide all IESO records (including draft reports, notes, emails, internal and external meeting materials, etc.) of its consideration and/or evaluation of possible imports from Quebec and New York to satisfy the identified ~2,000 MW need.

j) Please provide all IESO records (including draft reports, notes, emails, internal and external meeting materials, etc.) relied upon to reach its conclusion that “the amount we’re aware of isn’t enough to meet the approximately 2,000 MW need and/or it is unclear whether or not it can be developed/acquired in 2026”.

Response:

The following response has been provided by the IESO.

a) The IESO relied upon its knowledge of the market and did not undertake specific outreach to supply resource developers and existing operators on this matter. The system need east of FETT that will arise due to the Pickering GS retirement has been communicated to the marketplace, including in the IESO's 2020 Annual Planning Outlook[1], and should be well known to resource developers and existing operators. Despite the publicized need, the IESO was not, and is not, aware of planned projects that are in a sufficiently advanced stage of development that could, individually or collectively, meet the approximately 2,000 MW need east of FETT by 2026. There are no projects east of FETT with completed System Impact Assessments nor, to the IESO's knowledge, are there projects east of FETT with ongoing public/Indigenous consultations. Further, the IESO's Capacity Auction[2] design is currently unable to accommodate import volumes of this magnitude.

b) The IESO provides supply resource developers and existing operators with various forums and ad hoc opportunities to engage with the IESO. As noted in response to part a), above, the IESO has communicated the system need east of FETT by 2026 to the marketplace and did not undertake specific outreach to supply resource developers and existing operators.

c) The interest for resources developments includes gas-fired generation, nuclear generation, and storage facilities. Some of these involve large capacity, but most of these are at a preliminary stage. None of the proponents for these projects indicted an in-service date of 2026 or earlier.

d) The IESO did not consider potential procurement and revenue mechanisms in making its determination of need. As detailed in response to part a), above, the IESO is not aware of planned projects that are in a sufficiently advanced stage of development that could, individually or collectively, meet the approximately 2,000 MW need east of FETT by 2026. This assessment would not have been affected by considering different potential procurement and revenue mechanisms.

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[1] https://www.ieso.ca/en/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook

[2] https://www.ieso.ca/en/Sector-Participants/Market-Operations/Markets-and-Related-Programs/Capacity-Auction

e) No. Please see the responses to parts a) and d), above.

f) The IESO has not considered the continued operation of Pickering GS beyond the current end-of-life of 2024/2025 as such information has not been provided by the facility owner.

g) The IESO did not utilize a generic development timeline in its assessment. As detailed in response to part a), above, the IESO is not aware of any projects that are in an advanced stage of development and could, individually or collectively, provide it with the degree of comfort necessary to meet the approximately 2,000 MW need east of FETT by 2026.

h) The IESO will not provide the requested records as they are not relevant or proportional to the issues before the OEB. Please see the response to question a) for the basis of the IESO's assessment.

i) Please see the response to question h).

j) Please see the response to question h).

ASSOCIATION OF POWER PRODUCERS OF ONTARIO INTERROGATORY #3

Reference:
Exhibit B-3-1, Attachment 3, page 7 of 13

Preamble:
As previously stated, section 3.2 of the Report states that "[t]he IESO is aware of some interest in developing new supply east of the interface and imports from Quebec and New York could provide some of that supply; however, the amount we're aware of isn't enough to meet the approximately 2,000 MW need and/or it is unclear whether or not it can be developed/acquired by 2026."

Section 3.3 of Report states in part that "[t]here are uncertainties on the capacity level that can be obtained east of FETT through the target capacity auction process and other resource acquisition mechanisms under development."

Interrogatory:

a) Please specify the "other resource acquisition mechanisms under development".

b) Please provide all IESO records (including draft reports, notes, emails, internal and external meeting materials, etc.) relied upon to reach its conclusion that "[t]here are uncertainties on the capacity level that can be obtained east of FETT through the targeted capacity auction process".

c) To the extent they are not provided in response to the above interrogatories, please provide all IESO records (including draft reports, notes, emails, internal and external meeting materials, etc.) relied upon to reach its conclusion that "[t]here are uncertainties on the capacity level that can be obtained east of FETT through … other resource acquisition mechanisms under development".

d) Please identify and delineate which alternative solutions were not pursued due to insufficient capacity and which were not pursued due to lack of clarity as to whether the supply could be developed/acquired by 2026.

e) Please identify and explain the extent to which procurement models and revenue mechanisms identified in response to 2.1-APPrO-2 above impacted or influenced determinations of availability and certainty?

f) Please provide a summary of capacity offered east of FETT in the December 2020 capacity auction, including the following information:
   i. Quantity of capacity (MW)
   ii. Fuel type (e.g., gas-fired generation, energy storage, imports, etc.)
   iii. Capacity price offered[1]
   iv. Location of capacity offered

Response:

The following response has been provided by the IESO.

a) The "other resource acquisition mechanisms under development" are the Mid-Term Request For Proposal (RFP) and the Long-Term RFP that are being considered in the IESO's Resource Adequacy Engagement. More information on the IESO's Resource Adequacy Engagement is available on the IESO's website[2].

b) The IESO Capacity Auction is limited to demand response, existing resources and imports and cannot supply the volume of capacity needed to meet the identified need. The IESO will not provide the requested records.

c) The IESO has explained the basis for its assessment above in this response and in responses to Exhibit I, Tab 4, Schedules 1 and 2. The IESO will not provide the requested records.

[1] APPrO understands this information may need to be partially redacted or aggregated to maintain commercially sensitive information.
[2] https://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Resource-Adequacy-Engagement

d) The IESO's assessment of alternative solutions was based both on the amount of capacity available and whether it could be provided in a timely manner. If the proposed RTR Project is not developed, the IESO will require approximately 2,000 MW of new capacity east of FETT by 2026 to be compliant with its reliability obligations. As explained in response to Exhibit I, Tab 4, Schedule 2, part a), the IESO is not aware of planned projects that are in a sufficiently advanced stage of development that could, individually or collectively, meet the approximately 2,000 MW need east of FETT by 2026.

e) As explained in response to Exhibit I, Tab 4, Schedule 2, part d), the procurement models and revenue mechanisms did not influence the IESO's assessment.

f) Please refer to Table 1, below, for a summary of capacity offered east of FETT in the December 2020 by zone, resource type, and enrolled capacity.

Table 1 – Summary of Capacity Offered

Zone	Resource Type	Enrolled Capacity (MW)
East	Virtual Hourly Demand Response	142.9
	Capacity Generation Resource	103
	Physical Hourly Demand Response	18
ESSA	Virtual Hourly Demand Response	51.5
Ottawa	Virtual Hourly Demand Response	66.1
	System-Backed Import Resource	80
	Dispatchable Load Resource	25
Toronto	Virtual Hourly Demand Response	383.8
	Dispatchable Load Resource	72
Northeast	Dispatchable Load Resource	5
	Virtual Hourly Demand Response	57.6
	Capacity Storage Resource	1.7
Northwest	Virtual Hourly Demand Response	2.1

CAPITAL POWER CORPORATION INTERROGATORY #1

Reference:
Exhibit B-3-1, Attachment 3

Preamble:
In Section 1 of the IESO's June 12, 2021, report titled *Trafalgar TS x Richview TS 230 kV line upgrade: Need and Selection of the Preferred Plan* (the "Report") the IESO states, in part, that supply capacity east of the FETT interface is "expected to decline due to nuclear retirements and nuclear refurbishments, and could potentially decline towards the end of this decade due to contracts for generation facilities reaching the end of their terms."

The IESO goes on to state that "[t]his decline in supply contributes to an overall provincial need for capacity (see the 2020 Annual Planning Outlook), where due to limitations on the transfer capability of the FETT interface 1850 to 2250 MW of that capacity must be acquired east of the interface by 2026. More specifically, with the decline in supply capacity east of the FETT interface, studies show that the transfer capability of the FETT interface will not be sufficient to meet NERC and NPCC reliability requirements by 2026 requiring, approximately 2000 MW of supply to be specifically acquired east of FETT."

Interrogatory:

a) Is the 2000 MW an Unforced Capacity (UCAP) value? If so, please provide analysis showing calculations of the total installed capacity required to provide 2000 MW of UCAP for the following resource types: gas-fired generation, energy storage, imports from New York, imports from Quebec, and Demand Response.

   If the 2000 MW is not a UCAP value, please explain what value it does represent and why UCAP was not used.

b) Please provide in readable format (e.g., .xls, .csv) the hourly load flow estimates for the FETT interface for the years 2024 to 2030 used in the IESO's analysis of system need.

c) Please provide the FETT loading conditions for normal and contingency operating conditions.

d) Please indicate the FETT transfer capability for normal and contingency operating conditions.

e) Please identify the expected number of hours and magnitude (i.e., in MW) of constraint used to define system need. Please provide the demand outlook and system conditions underpinning the estimate.

f) Does the forecast used for system need utilize the IESO Annual Planning Outlook Demand Outlook scenario 1 or scenario 2? If neither scenario is used, please describe the scenario used for the IESO's system analysis and provide an explanation why a new demand outlook was required. Please provide assumptions used to generate a new demand outlook.

g) With respect to the IESO's estimate of need for 2000 MW of resources east of FETT, please provide the following operating attributes the IESO expects to the resources to have and/or provide:
   i. Hours of operation required during constrained time periods
   ii. Ramping capabilities
   iii. Locational requirements to resolve system need

h) What forced outage assumptions for existing and committed resources were incorporated in the IESO's analysis estimating a need of 2000 MW of new resources as an alternative to the preferred plan?

i) Did the IESO perform a probabilistic analysis assessing the frequency and duration of coincident forced outages for existing generation and transmission across the FETT interface? If so, please provide details and findings of the probabilistic analysis and explain whether the analysis aligned with the *Ontario Resource and Transmission Assessment Criteria* ("ORTAC") for load restoration. If the analysis was not performed, please explain why it was not undertaken.

Response:

The following response has been provided by the IESO.

a) Unforced capacity is applicable to resource adequacy requirements. The east of FETT need is based on transmission security requirements. Transmission security requirements are governed by NERC TPL-001 and Table 1 of NPCC Directory #1. Transmission security assessment is not an hourly analysis. It is a deterministic analysis that compares the demand at peak demand periods against the available resources east of FETT and the established FETT transfer capability. Installed capacity available during summer peak plus any firm import was used in the FETT transmission security assessment. This assessment does not consider generation forced outages. However, due to the nature of resources, historical hydroelectric generation output and reduced values for variable generation, such as wind and solar, are used.

b) Please refer to the response in part a), above.

c) The flow levels for the FETT transmission security tests for year 2026 are: 6,460 MW for all elements in-service and 4,780 MW with one critical element out of service. These are for APO 2020 demand forecast S1.

d) The FETT transfer capability for year 2026 is: 4,230 MW for all element in-service and 2,580 MW for one critical element out of service.

e) Please see response to part c), above.

f) The IESO Annual Planning Outlook Demand Outlook Scenario 1 and Scenario 2 were used.

g) For the purposes of recommending the RTR Project it wasn’t necessary to determine these detailed resource attributes.

h) Please refer to the response in part a), above.

i) As indicted above, transmission security requirements are based on deterministic performance criteria. The analysis is aligned with the Ontario Resource and Transmission Assessment Criteria ("ORTAC")1 but the nature of the FETT interface study does not consider load restoration.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/connecting/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

CAPITAL POWER CORPORATION INTERROGATORY #2

Reference:

Exhibit B-3-1, Attachment 3

Preamble:

Section 1 of the IESO's Report states, in part, that supply capacity east of the FETT interface is "expected to decline due to nuclear retirements and nuclear refurbishments, and could potentially decline towards the end of this decade due to contracts for generation facilities reaching the end of their terms."

Section 3 of the IESO's Report states that "[a]s indicated in the 2020 Annual Planning Outlook, in addition to this specific need for capacity east of the FETT interface, there is an overall need for capacity in Ontario due to increasing demand for electricity and the retirement of Pickering GS combined with nuclear unit outages for refurbishment. For the year 2026, that amount was determined to be about 5,200 MW after re-acquiring Lennox GS and 3400 MW assuming all other resources with expiring contracts in the province are re-acquired."

Interrogatory:

a) Please identify what assumptions the IESO relied on with respect to the continued operation of existing generation facilities for the purpose of assessing the alternative options and the preferred option.

b) Has the IESO has determined that under both demand scenarios considered in the Annual Planning Outlook that the resource adequacy need for the years 2026 to 2040 exceeds 2000 MW? If additional demand scenarios were used in the IESO's analysis of the preferred and alternative options, please confirm whether the resource adequacy need exceeds 2000 MW under the additional demand scenarios.

c) In its assessment of alternative solutions, did the IESO value the ability of new supply resources to solve both the provincial capacity need and needs related to the FETT interface constraint? If yes, please provide details of the valuation methodology including details of the analysis, data and assumptions used to inform the analysis. If no, please explain why the IESO declined to undertake this analysis.

Response:

The following response has been provided by the IESO.

a) The figures in Table 2 of the IESO Report show the raw need – without the reacquisition of resources after their contract term. However, continued operation of Lennox GS at least to 2026 was assumed for the purpose of assessing the alternative options and the preferred option.

b) The need for capacity east of FETT in 2026 would be 2,250 MW under Scenario 1 and 1,800 MW under Scenario 2 as indicated in Exhibit B, Tab 3, Schedule 1, Attachment 3, page 5 of the IESO's need evidence. No other demand scenario was used for the transmission security assessment.

c) As explained in response to Exhibit I, Tab 4, Schedule 2, part a), the proposed reconductoring project is required to meet North American reliability standards requirements as set out in NERC TPL-001 and NPCC Directory #1. The reliability standards require a pass or fail deterministic assessment and are not based on an assessment of value.