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BY EMAIL AND RESS

September 4, 2024

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

Dear Ms. Marconi,

EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – St. Clair Transmission Line Project – Interrogatory Responses

In accordance with Procedural Order No.1, issued July 31, 2024, (Procedural Order No. 1) please find attached an electronic copy of responses provided by Hydro One to interrogatory questions posed by intervenors and Ontario Energy Board ("OEB") Staff.

Intervenor interrogatory responses have been assigned Exhibit I. OEB Staff interrogatories have been assigned Tab 1 of Exhibit I and all other intervenors interrogtaories have been organized consistent with the manner the intervenors were listed in Schedule A of Procedural Order No. 1. Thus, the interrogatory responses have been organized in the following order:

Exhibit	Tab	Intervenor
I	1	OEB Staff
I	2	Enbridge Gas Inc.
I	3	Kevin Jakubec
I	4	The Siskinds Firm Group
I	5	The Ross Firm Group
I	6	Vector Pipeline Inc.

Hydro One has, pursuant to Rule 10 of the Ontario Energy Board's (OEB) Rules of Practice and Procedure (the "**Rules"**) and the OEB's Practice Direction on Confidential Filings dated December 17, 2021 (the "**Practice Direction**"), requested confidential treatment of certain information contained in its responses to OEB staff interrogatories as follows;

- **Exhibit I, Tab 1, Schedule 6 part a)** – seeking information regarding the calculation of the Project's annual line losses;
- **Exhibit I, Tab 1, Schedule 10 parts a, and f through h** - pertaining to requests for Engineering, Procurement and Construction ("EPC") contract information,
- **Exhibit I, Tab 1, Schedule 11** - pertaining to requests for Engineering, Procurement and Construction ("EPC") contract pricing information; and

- **Exhibit I, Tab 1, Schedule 12g and 12m-** pertaining to requests for Engineering, Procurement and Construction ("EPC") contract pricing information.

In accordance with subsection 6.1.2, 6.1.4 and 6.1.7 of the Practice Direction and subsections 10.01 and 10.02 of the Rules, Hydro One has proposed that the confidential versions of its responses to OEB staff interrogatories 10(a), 10(f)-(h), 11, 12(g) and 12(m) be disclosed to *only counsel* for OEB Staff from whom the OEB accepts a Declaration and Undertaking.

With respect to the foregoing requests, by way of separate filing, Hydro One's counsel will be filing a motion consistent with the Practice Direction.

Regarding the go forward hearing process, Hydro One maintains the view that review of the application should proceed as efficiently as possible. Many of the intervener interrogatories touch upon issues that are beyond the scope of the issues set out in Procedural Order No. 1 and no intervenor evidence has been filed in this proceeding. In order for timing efficiencies and priority project objectives to be achieved, Hydro One proposes having Board Staff and interveners file their written final arguments first, and for Hydro One to then have reasonable time to review and then provide its written final argument, which would include any reply submissions to arguments made by Staff and interveners. This approach is intended to shorten the more traditional argument phase whereby Hydro One, as applicant, would submit its final argument first, and then file reply submissions following review and receipt of Staff and intervener argument submissions. This procedural suggestion is not novel and is akin to the procedural steps outlined by the OEB in the OEB's Short Form Leave to Construct Performance Standards[1].

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

Sincerely,

Pasquale Catalano on behalf of Joanne Richardson

[1] OEB Correspondence – Updates to Performance Standards and Other Process Improvements, Appendix B – March 29, 2021

OEB STAFF INTERROGATORY - 01

Reference:
Exhibit B-1-1, Pages 2-3

Preamble:
Hydro One states that the transmission line facilities comprising the Project will be owned by a future limited partnership through which Hydro One will offer equity ownership to impacted First Nations.

Hydro One further states that, as of the time of filing the application, the limited partnership has not yet been finalized Hydro One is not able to provide commercial details.

Interrogatory:
a) Please confirm if the limited partnership has been finalized and provide an update on which groups are involved.

b) If negotiations have advanced to a stage where commercial details can be provided, please describe the proposed ownership model as well as any other information that provides insight on the structure of the future partnership.

Response:
a) No, the limited partnership and corresponding commercial details have not been finalized. The Indigenous communities that will have the opportunity to participate in the equity ownership model include:
   - Aamjiwnaang First Nation;
   - Bkejwanong (Walpole Island) First Nation;
   - Caldwell First Nation;
   - Chippewas of Kettle and Stony Point First Nation; and
   - Chippewas of the Thames First Nation.

b) Please refer to the response in part a) above. The negotiations have not advanced to a stage where commercial details can be provided.

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OEB STAFF INTERROGATORY - 02

Reference:
Exhibit B-3-1, Attachment 1, Page 6

Preamble:
In the System Impact Assessment, it is stated that through the Environmental Assessment process, Hydro One identified route options that utilize the existing 115 kilovolt ("kV") transmission line (N5K) that currently supplies Wallaceburg TS. This would require (1) N5K be converted to a 230 kV line, forming part of the Project, and (2) Wallaceburg TS be upgraded from a 115 kV TS to a 230 kV TS, being supplied by the Project.

Interrogatory:

a) Please briefly describe Hydro One's route selection process. As part of the description, please clearly articulate the reasons for why the preferred route was selected.
   i. When responding, please specifically identify the steps Hydro One has taken to ensure that a cost-effective route is selected.

b) Please briefly describe each route option considered during the EA process, including identifying the advantages and disadvantages of each.

c) What feedback did Hydro One receive from affected communities with respect to the selected route and other alternatives?
   i. If there was opposition expressed, please detail the specific concerns and how Hydro One has addressed these concerns in the final route.

Response:

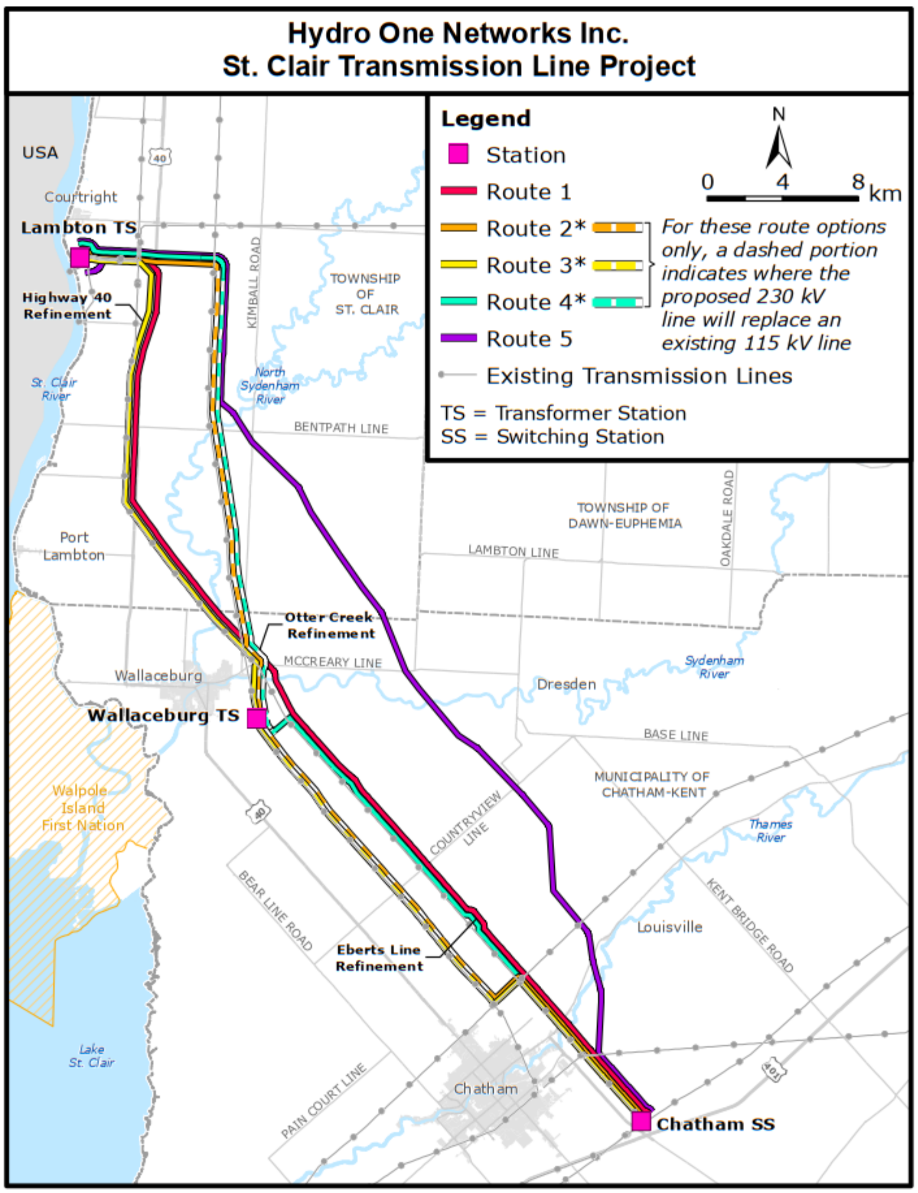
a) A Class Environmental Assessment ("Class EA") is a standardized planning process approved under Ontario's *Environmental Assessment Act* ("EAA")[1] for certain classes (groups) of projects that have predictable and manageable environmental effects, to which the SCTL Project qualifies. Hydro One's route selection process adheres to the requirements established within the Class EA process[2].

   Hydro One's route selection process started with the identification and mapping of viable route alternatives to be studied and evaluated in the Class EA. This process was conducted by the Project team, which included consultants specialized in linear route identification and modelling. As part of this process, readily available secondary

[1] https://www.ontario.ca/laws/statute/90e18
[2] Class Environmental Assessment for Minor Transmission Facilities (2022) was the current version at the time of the Project commencement.

sources were referenced to map various technical and environmental constraints and opportunities from Lambton TS to Chatham SS. Hydro One subject matter experts also identified opportunities to parallel and repurpose existing transmission line corridor lands. This resulted in the identification of five viable route alternatives to be assessed and evaluated during the Class EA process. These route alternatives are shown in the map below (as provided in Figure 5-2 Route Alternatives, Variations and Refinements of the St. Clair Transmission Line Environmental Study Report ("Final ESR")).

Figure 5-2: Route Alternatives, Variations and Refinements



During the Class EA, these five routes were further assessed by conducting various studies and field programs to characterize the local environment and their interactions. Based on project consultation efforts, four key evaluation categories were identified, each with multiple criteria and measures used to comparatively evaluate the potential environmental effects of each route alternative (these are described in Chapter 5, Table 5-1 of the Final ESR). The evaluation was completed using a Weighted Multi-Criteria Decision-Making Process, having regard for each of the evaluation categories as identified in Section 5 of the Final ESR.

A draft of the ESR was available on Hydro One's website[3] for public review and comment for 30 days from November 6, 2023, to December 7, 2023. The Final ESR was filed on February 5, 2024. In both the draft and Final ESR, Table's 5-9 through 5-12 show the breakdown of criteria and measures under each of the four categories and Table 5-13 presents an overview of the final weighted scores of each category comparing them against each other. For ease of reference, a summary of why Route Alternative 2 was selected is below.

Overall, Route Alternative 2 is preferred because it minimizes the overall impact to the Natural and Socio-Economic Environments compared to the other route alternatives and minimizes impacts to agricultural lands by utilizing existing transmission corridors for approximately 80% of its total length. From an Indigenous Culture, Values and Land Use perspective, Route Alternative 2 avoids a separate crossing of the Thames, North Sydenham and Sydenham Rivers, minimizes impacts to native habitats and natural or naturalized areas which support hunting and harvesting activities, and provides improved transmission reliability to an Indigenous community supplied from the Wallaceburg TS. From a Technical and Cost perspective, Route Alternative 2 ranked in the middle of the five route alternatives under consideration, though it should be noted that the weighted scores for all five routes in this category were within a very close range (in contrast to the other three evaluation categories). Route Alternative 2 is the most preferred route from a real estate perspective, as it maximizes the ability to utilize existing transmission corridors. Route Alternative 2 also results in improvements to the reliability and efficiency of the transmission system supply to the Wallaceburg area through an upgrade to the Wallaceburg TS.

b) The Final ESR provides a detailed evaluation of each route alternative and the rationale for the selection of the preferred route. Below is a summary of the advantages and disadvantages of each route alternative considered.

[3] https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/saint-clair

Route 1 parallels an existing 230 kV double-circuit transmission line between Lambton TS and Chatham SS on the east side and would involve widening the existing corridor. Deviations from the existing 230 kV corridor southeast of Lambton TS were proposed to minimize the effects to the large woodlots and other natural features in the area. As described in detail in Section 5 of the Final ESR, this route was the second worst for co-location and repurposing of existing infrastructure and included the greatest amount of incompatible vegetation requiring removal, and greatest amount of sensitive wildlife habitat within the studied right-of-way ("ROW") and Project Study Area. It did have the smallest area for agricultural land in the ROW and was the shortest length of line.

Route 2 (preferred route) involves the replacement of the existing 115 kV single-circuit transmission line with a new 230 kV double-circuit transmission line following the same corridor. The distance over which this replacement occurs comprises the majority of this routing alternative from just east of Lambton TS (Kimball Junction) to just north of the Chatham urban centre (Kent Junction). As such, this results in replacing the existing transmission lines and structures, as well as proportional widening of the existing ROW. It also requires Wallaceburg TS to be upgraded from 115 kV to 230 kV. This alternative was the best for co-location and repurposing of existing infrastructure and results in the least loss of incompatible vegetation, wildlife habitat and species-at-risk or potential species-at-risk in the ROW. While it does have the longest line length and highest number of light and heavy angled structures combined, it is the most preferred from a real estate perspective by maximizing the ability to utilize existing transmission corridors. While Route Alternative 2 (as well as Route Alternatives 3 and 4) require the conversion of the Wallaceburg TS from 115 kV to 230 kV and involve some additional effort to remove the existing 115 kV transmission lines and structures, these costs are largely offset by refurbishment costs that would otherwise be required for the 115 kV transmission line. Additionally, the conversion of Wallaceburg TS from a single-circuit 115 kV supply to a double-circuit 230 kV supply will result in improved reliability and efficiency of the transmission system supply to the Wallaceburg area.

Route 3 is a combination of Route 1 and Route 2, whereby the new 230 kV double-circuit transmission line would parallel the existing 230 kV double-circuit transmission line along the east side of the existing corridor from Lambton TS to Wallaceburg TS and replace the existing 115 kV transmission line with a new 230 kV double-circuit transmission line from Wallaceburg TS to just north of Chatham. This alternative had the greatest amount of designated natural areas and identified habitat restoration areas, the highest areas of vulnerable aquifers, groundwater recharge areas and private wells. Additionally, it had the highest number of potential built heritage resources within 25 meters of the ROW. Route 3 did not have any commercial, industrial, institutional or recreational business facilities within the ROW that would require removal.

Route 4 is another combination of Route 1 and Route 2, whereby the existing 115 kV transmission line between Lambton TS and Wallaceburg TS would be replaced with a new 230 kV double-circuit transmission line and from Wallaceburg TS to Chatham SS, the route would parallel the existing 230 kV double-circuit transmission line on the east side of the existing corridor. This route alternative had the highest number and length of watercourse crossings, highest number of residential properties that overlap with the ROW and Local Study Area and the highest number of mandatory buyouts. It had the lowest number of potential built heritage resources within 25 meters of the ROW.

Route 5 represents a predominantly new greenfield transmission line corridor between the Lambton TS and Chatham SS, except for short segments near each station where the new transmission line would parallel existing transmission lines. This alternative would require no conversion of Wallaceburg TS to 230 kV but would also not avoid upcoming refurbishment costs associated with the existing 115 kV line. This route alternative was ranked worst from a co-location and repurpose of existing infrastructure standpoint. The ROW for this alternative affected the greatest areas of wetlands, hazard lands, and regulated floodplain. Additionally, it would have the highest number of impacted properties, making it the worst for real estate considerations. However, it was ranked as the best from a surface water resources and aquatic habitat perspective due to the lowest number of watercourse crossings. It also would have the lowest number of potentially impacted archaeological features.

c) Hydro One’s public consultation and engagement initiatives are described throughout Chapter 3 of the Final ESR and also found in the Record of Consultation (Appendix B to the Final ESR).

Three route refinements were made to the original routes identified in the Notice of Commencement and were based upon feedback received from Hydro One’s stakeholder engagement and consultation process, and additional technical investigation conducted by Hydro One. These included refinements to the crossing at Otter Creek (refinements to Route 2, 3, 4), adjusting the corridor near Highway 40 (refinements to Route 1 and 3) and deviations made to avoid a wind farm facility (refinements to Routes 1 and 4). Hydro One provided notification of these refinements to affected property owners by way of registered mail to property owners affected by these changes and shared related information with members of the Technical Advisory Committee for the Project. Information about the refinements was presented at Community Open House #2 as well as being included on the Project website.

Concerns regarding the Otter Creek refinement and non-replacement of the existing 115 kV transmission line were raised. Hydro One continues to engage with individual property owners impacted by the Otter Creek refinement. This includes consultation on specific design components, such as tower placement locations. Additionally, Hydro One agreed to remove the small segment of the existing 115 kV transmission line given it did not represent a future use to the organization.

Hydro One has also provided property owners potentially affected by the SCTL Project with status updates sent by way of registered mail and employed a door-knocking service to visit all properties on each of the five route alternatives. Feedback received was recorded and responded to, included in Chapter 3 of the Final ESR, and considered in the Class EA and route selection process.

Hydro One also received positive feedback on its intention of using existing corridors for the Project as a means to reduce environmental and socio-economic impacts. As noted in the Final ESR the following rightsholders and stakeholders expressed this sentiment: Chippewas of the Thames First Nation, Bkejwanong (Walpole Island First Nation), Ontario Federation of Agriculture (OFA), and the Municipality of Chatham-Kent. Hydro One heard comments both questioning and opposing the selection of a greenfield route, in light of other alternatives being considered that would utilize existing transmission line corridors to varying extents.

Hydro One continues to consult and work with individual property owners along the preferred route on location specific detailed design elements of the Project.

OEB STAFF INTERROGATORY - 03

Reference:

Exhibit B-10-1, Pages 1-2

Preamble:

The need for the Project was identified in the Transmission System Plan included in Hydro One's most recent revenue requirement application, EB-2021-0110 at Exhibit B, Tab 2, Schedule 1 Section 2.11 and more specifically discussed in Investment Summary Document (ISD) ISD T-SS-09 for the West of London Transmission Reinforcement.

Hydro One states at the above reference that it recognizes that there is a cost difference between the forecast cost of $76.8 million for the terminal station modification work at Lambton TS and Chatham SS that underpinned the ISD and the cost to execute the Project ($137.4 million) filed in this Application at Table 2 of Exhibit B, Tab 7, Schedule 1.

Interrogatory:

a) Please provide a detailed list of the specific costs and reasons associated with the approximately $60.6 million difference in costs.

b) If applicable, please list any other costs which may affect the project cost as stated that were not considered at the time of the filing of this Application.

Response:

a) As described in Exhibit B, Tab 10, Schedule 1, most of the cost difference between those proposed in this Application and those that underpinned the forecast provided in the Transmission System Plan ("TSP") included in Hydro One's most recent revenue requirement application, EB-2021-0110, is driven by the Wallaceburg TS station work which is currently forecast to cost $48.9 million. This represents approximately 80% of the cost difference. The Wallaceburg TS station work resulted from identification of the preferred route which was determined through the Class EA process. The Class EA process commenced following the development of the TSP. As a result, costs associated with Wallaceburg TS were not accounted for in the estimate that underpinned the TSP for this Project.

It is also important to note that the ISD described at Exhibit B, Tab 10, Schedule 1 (page 2 at line 4) does not account for the updated inflation assumptions for the periods of 2021 to 2023 that increased the capital costs referenced in the ISD by a proration factor of 1.0545[1], nor the inflationary adjustments that would occur over the Hydro One Transmission Custom IR period (2024 to 2027)[2] that were acknowledged and agreed to as part of the EB-2021-0110 Settlement. Since the Settlement and subsequent OEB Decision in that proceeding, the OEB has issued inflationary updates for the 2024 inflation factor for transmitters set at 5.4%[3], and the current 2025 inflation factor for transmitters set at 3.7%[4]. Implementing these inflationary updates alone to today, increases the estimate provided in the ISD by $11.3 million. This explains the remaining cost difference as inflation represents approximately 20% of the cost difference.

In summary, the Wallaceburg TS station work forecast cost of $48.9 million and the inflationary updates of $11.3 million combine to explain the difference in cost.

b) Not applicable.

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[1] EB-2021-0110 – Decision & Order – Issued: November 29, 2022 – Settlement Proposal (October 24, 2022), p. 31 of 117
[2] EB-2021-0110 – Decision & Order – Issued: November 29, 2022 – Schedule A, p. 6, Footnote 8
[3] OEB Letter Re: 2024 Inflation Parameters – Issued: June 29, 2023 – p. 1
[4] OEB Letter Re: 2025 Inflation Parameters – Issued: June 20, 2024 – p. 1

OEB STAFF INTERROGATORY - 04

Reference:
Exhibit B-7-1, Table 1-2, Page 1

Preamble:
At the above noted reference in Tables 1 and 2, Line and Station Costs are listed for the Project as shown below:

Table 1 - Line Cost

	Estimated Cost ($000's)
Materials	29,913
Labour	18,793
Equipment Rental & Contractor Costs	125,227
Sundry	5,207
Contingencies	27,950
Overhead [2]	6,444
Allowance for Funds Used During Construction [3]	41,803
Real Estate	79,156
Total Line Work	**$334,493**

Table 2 - Station Cost

	Estimated Cost ($000's)
Materials	29,111
Labour	24,916
Equipment Rental & Contractor Costs	47,691
Sundry	5
Contingencies	13,515
Overhead [2]	7,298
Allowance for Funds Used During Construction [3]	13,867
Real Estate	978
Total Station Work	**$137,381**

Interrogatory:

a) For both Table 1 and 2 please provide a detailed list of the costs included in the contingencies category and the reason for its inclusion.

b) Please describe how the contingency cost estimate for the Project compares to contingency cost estimates developed for projects of similar size and complexity undertaken by Hydro One.

c) How would Hydro One characterize the confidence of the cost estimate for the 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?

e) Please describe the process used to develop the real estate component of the project costs. What steps has Hydro One taken to mitigate these costs?

f) Are there any project components that have been identified as high risk for cost overruns? How are these being mitigated?

g) Please update Tables 3, 4 and 5 at Exhibit B, Tab 7, Schedule 1 to reflect the inflation adjustment factors that include the latest OEB annual inflation parameters for 2025. Additionally, please provide the results in Microsoft Excel format showing the calculations.

Response:

a) For context, Hydro One followed an industry established best practices methodology in developing the contingency utilizing a risk management model. The components of the risk management model are: obtain inputs from project team stakeholders; assess level of complexity and subsequent level of structured analysis required; plan a project specific risk model defining project objectives, risk thresholds, roles and responsibilities, and how the remaining risk processes will be implemented; identify all credible threats to the achievement of project objectives and if any opportunities exist that may possibly promote project objectives; analyze the likelihood of occurrence, degree of impact on occurrence, and the prioritization of identified risks slated for further analysis, respond by developing a strategy to treat the risk (i.e. accept, avoid, mitigate, transfer); and execute and control by implementing the planned strategy with continued monitoring and control to confirm effectiveness, make adjustments if needed, and ensure the planned results are achieved.

The risk management model included a qualitative risk analysis that score and rank risks to produce a prioritized list of identified risks and a quantitative risk analysis that numerically analyzes the individual and combined effect of identified risks on project objectives. Using a 3-point estimate, a simulation tool is utilized to run scenario iterations to produce degrees of confidence intervals. For the contingency allocation for the Project, the confidence interval was set at the 85th percentile. Such an analysis provides supporting information which reduces project uncertainty and enables informed decision making. It is important to note that the contingency allocation is not a funded liability for each individual risk cost but rather a probabilistic value based on their likelihood of occurrence.

Given the probabilistic nature of the contingency valuations, a detailed breakdown of the contingency by lines and stations is only available to the extent already presented in Table 1 and 2 above in the Preamble.

b) Please refer to Table 3 below for the comparison of contingency cost estimates relative to overall costs for projects of similar size and complexity recently undertaken by Hydro One.

Table 3 - Contingency Cost Comparison

	Waasigan Project- Phase 1	Waasigan Project- Phase 2	Chatham Lakeshore Project	SCTL Project
Line Cost	10.5%	9.5%	8.9%	8.4%
Station Cost	11.2%	12.3%	4.6%	9.8%

In addition to the details provided above that confirm that the contingency carried in this Project forecast is in-line with similar projects of this size and complexity, Hydro One notes that the contingency value is a project-specific forecast and will only be utilized if a risk actually materializes on a project that needs to be mitigated.

c) As documented in Exhibit B, Tab 7, Schedule 1, the cost estimates provided in Table 1 and 2 of that Schedule, and similarly the Project Schedule provided at Exhibit B, Tab 11, Schedule 1, are based on a project definition equivalent to a Class 3 AACE International (formerly the Association for the Advancement of Cost Engineering) estimate classification system. Footnote 4 of Exhibit B, Tab 7, Schedule 1, identifies that the expected accuracy of the estimate as per AACE is in the range of -20%/ +30%.

d) The Project cost estimate included in the Application was developed using internal estimates and quotes for internal labor costs and consultant fees. Third-party appraisers were engaged to assess market costs for key elements of land acquisition.

These costs were combined with market tested Engineering, Procurement and Construction costs for the Project. These combined project elements and their associated risks have been analyzed to develop the contingency allowance and overhead costs. The Project cashflow was analyzed to establish the AFUDC costs for the Project, which were integrated as part of a total project estimate confidence level of Class 3 AACE.

e) The process used to develop the real estate component of the project cost considers the following elements:

- The fair market value of the properties directly affected by the Project, as determined by third-party appraisers accredited by the Appraisal Institute of Canada;
- Payments (if any) that represent the change in value to the lands on an affected property not occupied by the Project, referred to as “injurious affection”, as determined by accredited third-party appraisers;
- Financial incentives under Hydro One’s voluntary land acquisition program to affected property owners to encourage the timely and cost-effective voluntary acquisition of required project property rights;
- Estimated payments for crop loss caused by the Project and related activities, as determined through Hydro One’s Crop Land Out of Production program;
- Estimated costs of third-party services to support the necessary land acquisitions (e.g., appraiser, agri-business, land agent, legal survey, conveyancing); and
- Reimbursement of reasonable legal review fees that affected property owners incur as part of Hydro One’s voluntary land rights acquisition program.

Hydro One has taken the following steps to mitigate the real estate component of the Project costs:

- Siting the Project corridor on lands where Hydro One can leverage existing requisite land rights, reducing the overall cost for land acquisition;
- Establishing a voluntary land acquisition program to reduce the reliance on expropriation which is expected to lead to higher costs and potentially delay the Project in-service date; and
- Selecting a project corridor that has relatively fewer full property buyouts than other route alternatives considered in the environmental assessment process, which reduces overall land acquisition costs.

For most third-party services (e.g., appraisal services, land agent services), these services were retained through a competitive RFP process to ensure highest value at competitive pricing.

f) The items that have been identified to predominantly contribute to contingency and thus have the highest risk of cost overruns are detailed in Exhibit B, Tab 7, Schedule 1, Section 1. Corresponding mitigation measures are also detailed therein. For example:

Risk:

"*Approvals, Permits and Authorizations: Risk of delays or cost escalation in obtaining required approvals including leave to construct, and all necessary land rights (e.g., should property owners refuse Hydro One's voluntary agreements leading to the necessity of expropriation) that may cause delay or disruption to the construction schedule and additional cost.*"

Mitigation:

"*Proactively submitted all regulatory applications, project permit and authorizations well in advance of the construction start of the Project, including the Final ESR with the MECP and this leave to construct application.*"

Hydro One continues to strive for ways to secure all necessary approvals and initiate construction of this Priority Project as soon as possible.

g) Please see below for updated Tables 3, 4 and 5 from Exhibit B, Tab 7, Schedule 1 to reflect the inflation adjustment factors that include the latest OEB annual inflation parameters for 2025 (i.e., 3.7%[1]). The Microsoft Excel format showing the calculation of the escalation adjustment for these updated Tables 3, 4, and 5, applying the latest OEB annual inflation parameter for 2025, is provided in Attachment 1 to this Schedule.

[1] https://www.oeb.ca/sites/default/files/OEBltr_2025%20inflation_updates_20240620.pdf

1 **Updated Table 3 - Costs of Comparable Line Projects**

Project	Woodstock Area Reinforcement (Line Cost)	Power South Nepean Project (Line Cost)	Chatham x Lakeshore Transmission Line (Line Cost)	St. Clair Transmission Line (Line Cost)
Circuit Operating Designation(s)	M32W/M31W plus K12/K7	S7M and E34M	C87H and C88H	L34C and L35C
Voltage	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice and Steel Pole	Steel Lattice and Steel Pole	Steel Lattice	Steel Lattice
Single or Double Circuit	Double	Double	Double	Double
Conductor	1443.7 kcmil ACSR/TW	997.2 kcmil ACSR/TW	1443.7 kcmil ACSR/TW	1443.7 kcmil ACSR/TW
Location	Southwest Ontario	Eastern Ontario	Southwest Ontario	Southwest Ontario
Project Surroundings	Urban-Rural Parallel to Karn Rd	Urban-Rural Parallel to Hwy 416	Mostly Rural Parallel to Hwy 401	Mostly Rural
In-Service Year	2012	2021	2025	2028
Estimate or Actual	Actual	Actual	Estimate	Estimate
OEB-Approved Cost Estimate	$42.9M[2]	$58.8M[3]	$235.3M[4]	–
Total Cost	$35,600K	$51,276K	$235,272K[5]	$334,493K
Less Adjustments:				
Real Estate	*$500K*	*$2,229K*	*$99,682K*[6]	*$114,400K*[7]
Underground Line	*N/A*	*N/A*	*N/A*	*$9,103K*
Micropile Foundation	*N/A*	*$6,730K*	*N/A*	*N/A*
Bypass	*$4,300K*	*$1,419K*	*N/A*	*N/A*
Comparable Costs, before Escalation	$30,800K	$40,898K	$135,590K	$210,990K
Escalation Adjustment[8]	$17,650K	$12,227K	$15,847K	N/A
Total Adjusted Comparable Cost	$48,450K	$53,125K	$151,437K	$210,990K
Approximate Length	13.6 km	12.2 km	49 km	64 km
Unit Cost	**$3,563K/km**	**$4,355K/km**	**$3,091K/km**	**$3,297K/km**

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[2] As per Section 92 leave to construct proceeding EB-2007-0027.
[3] As per Section 92 leave to construct proceeding EB-2019-0077.
[4] As per Section 92 leave to construct proceeding EB-2022-0140.
[5] As per Hydro One's Notification of Material Change to the Chatham to Lakeshore Project, dated November 3, 2023, this project is anticipated to be in-service one year ahead of schedule and approximately $15 million less than the total project cost estimate identified in the EB-2022-0140.
[6] This amount includes the direct real estate costs of $69,683K plus contingency carried for expropriation, interest and overhead.
[7] This amount includes the direct real estate costs of $79,156K (identified in Table 1) plus contingency carried for expropriation, interest and overhead.
[8] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications. Assumes 2025 rate for 2025-2028.

1 **Updated Table 4 - Costs of Comparable Station Projects (Chatham SS/Lambton TS)**

Project	Chatham SS (CxL Project)	Wawa TS (EWT Project)	Lakehead TS (EWT Project)	Chatham SS (SCTL Project)	Lambton TS (SCTL Project)
Technical	Add one new diameter, (3) 230kV circuit breakers, (8) disconnect switches, new relay building	Add two new diameters, (6) 230kV circuit breakers, (14) disconnect switches, new relay building	Add one new diameter, (5) 230kV circuit breakers, (16) disconnect switches, new relay building, plus (1) 230kV shunt reactor, (1) 230kV cap bank and associated equipment	Add one new diameter, (5) 230kV circuit breakers, (12) disconnect switches	Add two new diameters, (4) 230kV circuit breakers, (10) disconnect switches, new relay building
Location	Southwest Ontario	Northern Ontario	Northern Ontario	Southwest Ontario	Southwest Ontario
Project Surroundings	Mostly rural	Rural	Rural	Mostly rural	Mostly rural
Environmental Issues	None	None	None	None	None
In-Service Year	2025	2022	2022	2028	2028
Estimate or Actual	**Estimate**	**Actual**	**Actual**	**Estimate**	**Estimate**
OEB-Approved Cost Estimate	**$28.8M**[9]	**$44.8M**[10]	**$50.9M**[11]	–	–
Total Cost	**$28,788K**	**$51,700K**	**$57,700K**	**$34,981K**	**$53,501K**
Less Adjustments:					
Land Cost	*N/A*	*$169K*	*$4K*	*N/A*	*$1,239K*[12]
Shunt Reactor & Cap Bank	*N/A*	*N/A*	*$3,649K*	*N/A*	*N/A*
Comparable Costs, before Escalation	**$28,788K**	**$51,531K**	**$54,047K**	**$34,981K**	**$52,262K**
Escalation Adjustment[13]	$3,365K	$14,888K	$15,614K	N/A	N/A
Total Adjusted Comparable Cost[14]	**$32,153K**	**$66,419K**	**$69,661K**	**$34,981K**	**$52,262K**

[9] As per Section 92 leave to construct proceeding EB-2022-0140.
[10] As per Section 92 leave to construct proceeding EB-2017-0194.
[11] As per Section 92 leave to construct proceeding EB-2017-0194.
[12] This amount includes $895K of direct real estate costs (a portion of the $978K identified in Table 2) plus contingency carried for expropriation, interest and overhead.
[13] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.
[14] Hydro One notes that two of the comparable station projects associated with the EWT project were executed during the COVID pandemic and distinct adjustments have not been made to reflect any of these incremental costs incurred as a result of construction during the pandemic. For reference, all incremental costs (including COVID) for all three EWT stations cumulatively was $16.9 million as disclosed in the Final Report (EB-2017-0194) dated June 21, 2022.

1 **Updated Table 5 - Costs of Comparable Station Projects (Wallaceburg TS)**

Project	Chenaux TS	Parry Sound TS	Wallaceburg TS
Technical	Replace two 230/115kV 125MVA transformers and associated equipment, two 115kV breakers, new relay building, spill containment, drainage, and oil/water separator	Replace two 230/44kV 83MVA transformers and associated equipment, protection and control, spill containment, drainage, and oil/water separator	Install new 230 kV facilities, two 230/27.6 kV 83MVA transformers and associated equipment, protection and control, spill containment, drainage, oil/water separator and removal of existing 115 kV equipment and two existing buildings
Location	Eastern Ontario	Central Ontario	Southwest Ontario
Project Surroundings	Mostly rural	Mostly rural	Mostly rural
Environmental Issues	None	None	None
In-Service Year	2020	2023	2026
Estimate or Actual	**Actual**	**Actual**	**Estimate**
OEB-Approved Cost Estimate	N/A[15]	N/A[20]	–
Total Cost	**$45,036K**	**$24,156K**	**$48,900K**
Less Adjustments:			
Land Cost	*N/A*	*N/A*	*$100K*[16]
230kV Switching Facilities	*N/A*	*N/A*	*$2,106K*
Station Property Fence Line Expansion	*N/A*	*N/A*	*$2,271K*
Demolish/Removal Cost	*$2,016K*	*$587K*	*$1,190K*
Comparable Costs, before Escalation	**$43,020K**	**$23,569K**	**$43,233K**
Escalation Adjustment[17]	$9,985K	$3,314K	N/A
Total Adjusted Comparable Cost	**$53,005K**	**$26,883K**	**$43,233K**

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[15] This project was encompassed within a previous Hydro One revenue requirement application. The project was not subject to leave to construct approval by the OEB. Therefore, the specific investment does not have a discrete OEB approval to appropriately reference for the purposes of this comparison.
[16] This amount includes $83K of direct real estate costs (a portion of the $978K identified in Table 2) plus contingency carried for expropriation, interest and overhead.
[17] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

ATTACHMENT 1 – COMPARABLE PROJECT ESCALATION ADJUSTMENT CALCULATION – SCTL PROJECT

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 05

Reference:

Exhibit B-2-1, Pages 2-3

Preamble:

Hydro One indicates that the Chatham Switching Station will require modifications to accommodate the transmission line facilities for the proposed Project. Hydro One was previously granted leave to construct the Chatham x Lakeshore Line under OEB decision EB-2022-0140. This transmission line required station modifications at Chatham Switching Station.

Interrogatory:

a) Please describe the specific modifications at the Chatham Switching Station for both projects and provide details on how potential cost overlaps or redundancies could have been anticipated and managed, if at all.

Response:

a) The two projects are distinct and unique from one another; there are no redundancies or cost overlaps between the two. A description of the specific modifications at Chatham Switching Station are outlined below for each project.

The Chatham x Lakeshore Project (EB-2022-0140) included the construction of the following:

- One (1) new 230 kV diameter
- Three (3) 230 kV circuit breakers
- Six (6) 230 kV breaker disconnect switches
- Two (2) 230 kV line disconnect switches
- Two (2) 3-phase ground switches
- All associated protection and control equipment
- New control building
- Two (2) 70 nF surge capacitors

The SCTL Project (EB-2024-0155) includes the construction of the following:

- One (1) new 230 kV diameter
- Five (5) 230 kV circuit breakers
- Ten (10) 230 kV breaker disconnect switches
- Two (2) 230 kV line disconnect switches
- Two (2) 3-phase ground switches
- All associated protection and control equipment

Project planning work for the Chatham Switching Station for the Chatham x Lakeshore Project was well underway prior to the IESO's recommendations for the SCTL Project and subsequent Minister's Directives (Exhibit B, Tab 3, Schedule 1, Attachments 1 and 3). The IESO's recommendation for the SCTL Project is predicated on the completion of the Chatham x Lakeshore Project. Thus, the modifications for the SCTL Project leverages and expands on the work being completed under the Chatham x Lakeshore Project such that there is no overlap in cost or redundancy between the two projects, and both projects are delivered as cost-effectively as possible.

OEB STAFF INTERROGATORY - 06

Reference:

Exhibit B-5-1, Pages 2-3

Preamble:

At the above noted reference, Hydro One states that a detailed 50-year NPV analysis using a discount rate of 5.65% was conducted to evaluate which conductor provided the best NPV results. This study was done using varying values for the prices of energy and a capacity price of $143,640/MW consistent with Hydro One's Transmission Line Loss Guideline.

Interrogatory:

a) Please provide the calculations used to derive the information in Table 2 (p.3 in the reference).

b) Please explain the methodology for developing the "varying values for prices of energy" that were used in the calculations and justification for utilizing these values.

c) Beyond the NPV analysis, please explain if there are any other considerations in choosing between the four conductor alternatives.

Response:

a) The calculation of the Annual Losses (MWh) shown in Table 2 of Exhibit B, Tab 5, Schedule 1 is performed in an MS Excel workbook and is referred to as Attachment 1 to this Schedule. Attachment 1 has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

   The details of NPV calculations shown in Table 2 of Exhibit B, Tab 5, Schedule 1 are provided in Appendices 1 through 3 of this Schedule.

b) The transmission line loss evaluation was done in accordance with Hydro One's Transmission Line Loss Guideline that has been filed with the OEB. Consistent with similar leave to construct proceedings[1], an NPV evaluation was completed using a range of energy prices to address previous intervenor concerns regarding the value attributed to transmission line losses. The sensitivity analysis utilizes a lower limit to represent HOEP and an upper limit of $120/MWH price to represent the energy cost

[1] EB-2022-0140, EB-2023-0197, EB-2023-0198, EB-2023-0199

for losses in the event energy prices were to increase in the future. Under either extreme, Hydro One's selected conductor size was the most cost-effective.

c) To clarify, three conductor alternatives were evaluated for the Project, not four as the question poses. The main considerations in choosing between these three conductor alternatives were the IESO ampacity requirements and project costs.

Appendices 1 through 3

Appendix 1A – NPV Analysis of Alternative #1 at Energy Price of $47.30/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures	(333,512)	(333,512)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	87,793	537	3,514	6,746	6,207	5,710	5,253	4,833	4,446	4,091	3,763	3,462	3,185	2,931	2,696	2,480	2,282	2,099	1,931	1,777	1,635	1,504	1,384	1,273	1,171	1,077	991
Cost of Line Losses	(80,694)	0	(988)	(1,008)	(1,028)	(1,048)	(1,069)	(1,091)	(1,113)	(1,135)	(1,158)	(1,181)	(1,204)	(1,228)	(1,253)	(1,278)	(1,304)	(1,330)	(1,356)	(1,384)	(1,411)	(1,439)	(1,468)	(1,498)	(1,528)	(1,558)	(1,589)
Net Impact to Ratepayers	**(326,412)**	**(332,974)**	**2,526**	**5,739**	**5,179**	**4,662**	**4,184**	**3,742**	**3,334**	**2,956**	**2,606**	**2,282**	**1,981**	**1,702**	**1,443**	**1,202**	**978**	**770**	**575**	**393**	**224**	**65**	**(85)**	**(225)**	**(356)**	**(481)**	**(598)**
Discount Factor Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value		(332,974)	2,391	5,141	4,391	3,741	3,178	2,690	2,268	1,904	1,588	1,316	1,082	880	706	557	429	319	226	146	79	21	(27)	(67)	(101)	(128)	(151)
Cumulative Net Present Value ($k)	**(305,051)**	**(332,974)**	**(330,584)**	**(325,443)**	**(321,052)**	**(317,311)**	**(314,133)**	**(311,442)**	**(309,174)**	**(307,270)**	**(305,682)**	**(304,366)**	**(303,284)**	**(302,404)**	**(301,699)**	**(301,142)**	**(300,713)**	**(300,394)**	**(300,168)**	**(300,022)**	**(299,944)**	**(299,922)**	**(299,949)**	**(300,016)**	**(300,116)**	**(300,245)**	**(300,396)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	912	839	772	710	653	601	553	509	468	431	396	364	335	308	284	261	240	221	203	187	172	158	146	134	123	831
Cost of Line Losses	(1,621)	(1,654)	(1,687)	(1,721)	(1,755)	(1,793)	(1,829)	(1,866)	(1,903)	(1,941)	(1,980)	(2,020)	(2,060)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	(2,101)	0
Net Impact to Ratepayers	**(709)**	**(815)**	**(915)**	**(1,010)**	**(1,102)**	**(1,192)**	**(1,276)**	**(1,357)**	**(1,435)**	**(1,511)**	**(1,584)**	**(1,655)**	**(1,725)**	**(1,793)**	**(1,818)**	**(1,840)**	**(1,861)**	**(1,880)**	**(1,898)**	**(1,914)**	**(1,929)**	**(1,943)**	**(1,956)**	**(1,967)**	**(1,978)**	**831**
Discount Factor Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value	(170)	(184)	(196)	(205)	(212)	(217)	(220)	(221)	(221)	(220)	(219)	(216)	(213)	(210)	(201)	(193)	(185)	(177)	(169)	(161)	(154)	(146)	(140)	(133)	(126)	53
Cumulative Net Present Value ($k)	**(300,566)**	**(300,750)**	**(300,946)**	**(301,151)**	**(301,363)**	**(301,579)**	**(301,799)**	**(302,020)**	**(302,241)**	**(302,461)**	**(302,680)**	**(302,896)**	**(303,110)**	**(303,319)**	**(303,521)**	**(303,714)**	**(303,898)**	**(304,075)**	**(304,244)**	**(304,405)**	**(304,558)**	**(304,705)**	**(304,844)**	**(304,977)**	**(305,104)**	**(305,051)**

Appendix 1B – NPV Analysis of Alternative #1 at Energy Price of $120/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures	(333,512)	(333,512)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	87,793	537	3,514	6,746	6,207	5,710	5,253	4,833	4,446	4,091	3,763	3,462	3,185	2,931	2,696	2,480	2,282	2,099	1,931	1,777	1,635	1,504	1,384	1,273	1,171	1,077	991
Cost of Line Losses	(180,152)	0	(2,205)	(2,250)	(2,295)	(2,341)	(2,387)	(2,435)	(2,484)	(2,534)	(2,584)	(2,636)	(2,689)	(2,743)	(2,798)	(2,853)	(2,911)	(2,969)	(3,028)	(3,089)	(3,151)	(3,214)	(3,278)	(3,344)	(3,411)	(3,479)	(3,548)
Net Impact to Ratepayers	**(425,871)**	**(332,974)**	**1,309**	**4,497**	**3,912**	**3,370**	**2,866**	**2,398**	**1,962**	**1,557**	**1,179**	**826**	**497**	**188**	**(101)**	**(373)**	**(629)**	**(869)**	**(1,097)**	**(1,312)**	**(1,516)**	**(1,710)**	**(1,894)**	**(2,071)**	**(2,239)**	**(2,401)**	**(2,557)**
Discount Factor Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value		(332,974)	1,239	4,028	3,317	2,704	2,177	1,724	1,335	1,003	719	477	271	97	(50)	(173)	(275)	(361)	(431)	(487)	(533)	(569)	(597)	(617)	(632)	(641)	(646)
Cumulative Net Present Value ($k)	**(332,369)**	**(332,974)**	**(331,736)**	**(327,707)**	**(324,390)**	**(321,686)**	**(319,510)**	**(317,786)**	**(316,451)**	**(315,448)**	**(314,729)**	**(314,252)**	**(313,981)**	**(313,884)**	**(313,934)**	**(314,106)**	**(314,382)**	**(314,742)**	**(315,173)**	**(315,660)**	**(316,193)**	**(316,762)**	**(317,359)**	**(317,977)**	**(318,609)**	**(319,250)**	**(319,896)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	912	839	772	710	653	601	553	509	468	431	396	364	335	308	284	261	240	221	203	187	172	158	146	134	123	831
Cost of Line Losses	(3,619)	(3,692)	(3,766)	(3,841)	(3,918)	(4,004)	(4,084)	(4,166)	(4,249)	(4,334)	(4,421)	(4,509)	(4,599)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	(4,691)	0
Net Impact to Ratepayers	**(2,707)**	**(2,853)**	**(2,994)**	**(3,131)**	**(3,265)**	**(3,403)**	**(3,531)**	**(3,657)**	**(3,781)**	**(3,903)**	**(4,025)**	**(4,145)**	**(4,264)**	**(4,383)**	**(4,408)**	**(4,430)**	**(4,451)**	**(4,470)**	**(4,488)**	**(4,504)**	**(4,519)**	**(4,533)**	**(4,546)**	**(4,557)**	**(4,568)**	**831**
Discount Factor Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value	(648)	(646)	(642)	(635)	(627)	(618)	(607)	(595)	(583)	(569)	(556)	(542)	(527)	(513)	(488)	(465)	(442)	(420)	(399)	(379)	(360)	(342)	(324)	(308)	(292)	53
Cumulative Net Present Value ($k)	**(320,544)**	**(321,190)**	**(321,832)**	**(322,467)**	**(323,094)**	**(323,712)**	**(324,320)**	**(324,915)**	**(325,498)**	**(326,067)**	**(326,623)**	**(327,164)**	**(327,691)**	**(328,204)**	**(328,693)**	**(329,157)**	**(329,599)**	**(330,019)**	**(330,418)**	**(330,797)**	**(331,157)**	**(331,498)**	**(331,823)**	**(332,130)**	**(332,422)**	**(332,369)**

Appendix 2A – NPV Analysis of Alternative #2 at Energy Price of $47.30/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Capital Expenditures	(334,492)	(334,492)	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	88,052	537	3,524	6,766	6,225	5,727	5,269	4,847	4,460	4,103	3,775	3,473	3,195	2,939
Cost of Line Losses	(66,758)	0	(817)	(834)	(850)	(867)	(885)	(902)	(920)	(939)	(958)	(977)	(996)	(1,016)
Net Impact to Ratepayers	**(313,199)**	**(333,955)**	**2,707**	**5,933**	**5,375**	**4,860**	**4,384**	**3,945**	**3,539**	**3,164**	**2,817**	**2,496**	**2,198**	**1,923**
Discount Factor Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168
Annual Net Present Value		(333,955)	2,562	5,315	4,557	3,900	3,330	2,836	2,408	2,038	1,717	1,440	1,200	994
Cumulative Net Present Value	**(302,055)**	**(333,955)**	**(331,393)**	**(326,078)**	**(321,521)**	**(317,621)**	**(314,291)**	**(311,455)**	**(309,047)**	**(307,010)**	**(305,293)**	**(303,853)**	**(302,652)**	**(301,659)**

	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	2,704	2,488	2,289	2,106	1,937	1,782	1,640	1,508	1,388	1,277	1,175	1,081	994
Cost of Line Losses	(1,037)	(1,057)	(1,079)	(1,100)	(1,122)	(1,145)	(1,168)	(1,191)	(1,215)	(1,239)	(1,264)	(1,289)	(1,315)
Net Impact to Ratepayers	**1,667**	**1,430**	**1,210**	**1,005**	**815**	**638**	**472**	**318**	**173**	**38**	**(89)**	**(208)**	**(321)**
Discount Factor Full Year Discount @ 0.0565	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value	816	662	530	417	320	237	166	106	55	11	(25)	(56)	(81)
Cumulative Net Present Value	**(300,843)**	**(300,181)**	**(299,651)**	**(299,234)**	**(298,914)**	**(298,677)**	**(298,511)**	**(298,405)**	**(298,350)**	**(298,339)**	**(298,364)**	**(298,420)**	**(298,501)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	915	841	774	712	655	603	555	510	469	432	397	366	336
Cost of Line Losses	(1,341)	(1,368)	(1,395)	(1,423)	(1,452)	(1,484)	(1,513)	(1,544)	(1,575)	(1,606)	(1,638)	(1,671)	(1,704)
Net Impact to Ratepayers	**(427)**	**(527)**	**(621)**	**(711)**	**(797)**	**(881)**	**(959)**	**(1,033)**	**(1,105)**	**(1,174)**	**(1,241)**	**(1,305)**	**(1,368)**
Discount Factor Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237
Annual Net Present Value	(102)	(119)	(133)	(144)	(153)	(160)	(165)	(168)	(170)	(171)	(171)	(171)	(169)
Cumulative Net Present Value	**(298,603)**	**(298,722)**	**(298,856)**	**(299,000)**	**(299,153)**	**(299,313)**	**(299,478)**	**(299,646)**	**(299,816)**	**(299,988)**	**(300,159)**	**(300,329)**	**(300,499)**

	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	309	285	262	241	222	204	188	173	159	146	134	124	833
Cost of Line Losses	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	(1,738)	0
Net Impact to Ratepayers	**(1,429)**	**(1,454)**	**(1,477)**	**(1,498)**	**(1,517)**	**(1,535)**	**(1,551)**	**(1,566)**	**(1,580)**	**(1,592)**	**(1,604)**	**(1,615)**	**833**
Discount Factor Full Year Discount @ 0.0565	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value	(167)	(161)	(155)	(149)	(142)	(136)	(130)	(125)	(119)	(114)	(108)	(103)	53
Cumulative Net Present Value	**(300,666)**	**(300,827)**	**(300,982)**	**(301,130)**	**(301,273)**	**(301,409)**	**(301,540)**	**(301,664)**	**(301,784)**	**(301,897)**	**(302,005)**	**(302,109)**	**(302,055)**

Appendix 2B – NPV Analysis of Alternative #2 at Energy Price of $120/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures	(334,492)	(334,492)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	88,052	537	3,524	6,766	6,225	5,727	5,269	4,847	4,460	4,103	3,775	3,473	3,195	2,939	2,704	2,488	2,289	2,106	1,937	1,782	1,640	1,508	1,388	1,277	1,175	1,081	994
Cost of Line Losses	(149,040)	0	(1,824)	(1,861)	(1,898)	(1,936)	(1,975)	(2,015)	(2,055)	(2,096)	(2,138)	(2,181)	(2,224)	(2,269)	(2,314)	(2,361)	(2,408)	(2,456)	(2,505)	(2,555)	(2,607)	(2,659)	(2,712)	(2,766)	(2,822)	(2,878)	(2,936)
Net Impact to Ratepayers	**(395,481)**	**(333,955)**	**1,700**	**4,905**	**4,327**	**3,791**	**3,294**	**2,833**	**2,405**	**2,007**	**1,637**	**1,292**	**970**	**670**	**390**	**127**	**(119)**	**(350)**	**(568)**	**(773)**	**(967)**	**(1,150)**	**(1,324)**	**(1,489)**	**(1,647)**	**(1,797)**	**(1,941)**
Discount Factor Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value		(333,955)	1,609	4,394	3,668	3,042	2,502	2,036	1,636	1,292	998	745	530	346	191	59	(52)	(145)	(223)	(287)	(340)	(383)	(417)	(444)	(465)	(480)	(491)
Cumulative Net Present Value	**(324,656)**	**(333,955)**	**(332,346)**	**(327,952)**	**(324,284)**	**(321,242)**	**(318,740)**	**(316,703)**	**(315,067)**	**(313,775)**	**(312,777)**	**(312,032)**	**(311,502)**	**(311,156)**	**(310,965)**	**(310,906)**	**(310,959)**	**(311,104)**	**(311,327)**	**(311,614)**	**(311,954)**	**(312,337)**	**(312,754)**	**(313,198)**	**(313,663)**	**(314,143)**	**(314,634)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	915	841	774	712	655	603	555	510	469	432	397	366	336	309	285	262	241	222	204	188	173	159	146	134	124	833
Cost of Line Losses	(2,994)	(3,054)	(3,115)	(3,178)	(3,241)	(3,312)	(3,379)	(3,446)	(3,515)	(3,586)	(3,657)	(3,730)	(3,805)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	(3,881)	0
Net Impact to Ratepayers	**(2,080)**	**(2,213)**	**(2,341)**	**(2,465)**	**(2,586)**	**(2,709)**	**(2,824)**	**(2,936)**	**(3,046)**	**(3,154)**	**(3,260)**	**(3,365)**	**(3,469)**	**(3,572)**	**(3,597)**	**(3,619)**	**(3,640)**	**(3,660)**	**(3,677)**	**(3,694)**	**(3,709)**	**(3,722)**	**(3,735)**	**(3,747)**	**(3,758)**	**833**
Discount Factor Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value	(498)	(501)	(502)	(500)	(497)	(492)	(486)	(478)	(469)	(460)	(450)	(440)	(429)	(418)	(398)	(379)	(361)	(344)	(327)	(311)	(295)	(281)	(266)	(253)	(240)	53
Cumulative Net Present Value	**(315,131)**	**(315,633)**	**(316,134)**	**(316,635)**	**(317,131)**	**(317,624)**	**(318,109)**	**(318,587)**	**(319,057)**	**(319,517)**	**(319,967)**	**(320,406)**	**(320,835)**	**(321,253)**	**(321,652)**	**(322,031)**	**(322,392)**	**(322,736)**	**(323,063)**	**(323,374)**	**(323,669)**	**(323,950)**	**(324,216)**	**(324,469)**	**(324,709)**	**(324,656)**

Appendix 3A – NPV Analysis of Alternative #3 at Energy Price of $47.30/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures	(358,953)	(358,953)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	94,490	537	3,783	7,264	6,683	6,148	5,657	5,204	4,788	4,405	4,052	3,728	3,430	3,155	2,903	2,671	2,457	2,261	2,080	1,913	1,760	1,619	1,490	1,371	1,261	1,160	1,067
Cost of Line Losses	(54,762)	0	(670)	(684)	(698)	(711)	(726)	(740)	(755)	(770)	(786)	(801)	(817)	(834)	(850)	(867)	(885)	(902)	(921)	(939)	(958)	(977)	(996)	(1,016)	(1,037)	(1,057)	(1,079)
Net Impact to Ratepayers	**(319,225)**	**(358,416)**	**3,113**	**6,580**	**5,986**	**5,437**	**4,931**	**4,464**	**4,033**	**3,634**	**3,267**	**2,927**	**2,613**	**2,322**	**2,053**	**1,803**	**1,572**	**1,358**	**1,159**	**974**	**803**	**643**	**493**	**354**	**224**	**103**	**(11)**
Discount Factor Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value		(358,416)	2,947	5,895	5,075	4,363	3,745	3,209	2,744	2,341	1,991	1,689	1,427	1,200	1,004	835	689	563	455	362	282	214	155	106	63	27	(3)
Cumulative Net Present Value	**(319,525)**	**(358,416)**	**(355,469)**	**(349,575)**	**(344,500)**	**(340,137)**	**(336,391)**	**(333,182)**	**(330,438)**	**(328,098)**	**(326,107)**	**(324,418)**	**(322,992)**	**(321,792)**	**(320,788)**	**(319,953)**	**(319,264)**	**(318,700)**	**(318,245)**	**(317,883)**	**(317,601)**	**(317,387)**	**(317,232)**	**(317,126)**	**(317,063)**	**(317,035)**	**(317,038)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

	2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *	982	903	831	765	703	647	595	548	504	464	427	392	361	332	306	281	259	238	219	201	185	170	157	144	133	894
Cost of Line Losses	(1,100)	(1,122)	(1,145)	(1,168)	(1,191)	(1,217)	(1,241)	(1,266)	(1,292)	(1,317)	(1,344)	(1,371)	(1,398)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	(1,426)	0
Net Impact to Ratepayers	**(118)**	**(219)**	**(314)**	**(403)**	**(487)**	**(570)**	**(646)**	**(718)**	**(788)**	**(854)**	**(917)**	**(978)**	**(1,037)**	**(1,094)**	**(1,121)**	**(1,145)**	**(1,167)**	**(1,188)**	**(1,207)**	**(1,225)**	**(1,241)**	**(1,256)**	**(1,269)**	**(1,282)**	**(1,293)**	**894**
Discount Factor Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value	(28)	(50)	(67)	(82)	(94)	(104)	(111)	(117)	(121)	(125)	(127)	(128)	(128)	(128)	(124)	(120)	(116)	(112)	(107)	(103)	(99)	(95)	(91)	(87)	(83)	57
Cumulative Net Present Value	**(317,067)**	**(317,116)**	**(317,183)**	**(317,265)**	**(317,359)**	**(317,462)**	**(317,573)**	**(317,690)**	**(317,812)**	**(317,936)**	**(318,063)**	**(318,191)**	**(318,319)**	**(318,447)**	**(318,571)**	**(318,691)**	**(318,807)**	**(318,919)**	**(319,026)**	**(319,129)**	**(319,228)**	**(319,322)**	**(319,413)**	**(319,500)**	**(319,582)**	**(319,525)**

Appendix 3B – NPV Analysis of Alternative #3 at Energy Price of $120/MWHR

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

		Total	Period 0	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052	2053
Capital Expenditures		(358,953)	(358,953)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *		94,490	537	3,783	7,264	6,683	6,148	5,657	5,204	4,788	4,405	4,052	3,728	3,430	3,155	2,903	2,671	2,457	2,261	2,080	1,913	1,760	1,619	1,490	1,371	1,261	1,160	1,067
Cost of Line Losses		(122,258)	0	(1,496)	(1,527)	(1,557)	(1,588)	(1,620)	(1,653)	(1,686)	(1,719)	(1,754)	(1,789)	(1,825)	(1,861)	(1,898)	(1,936)	(1,975)	(2,015)	(2,055)	(2,096)	(2,138)	(2,181)	(2,225)	(2,269)	(2,315)	(2,361)	(2,408)
Net Impact to Ratepayers		**(386,721)**	**(358,416)**	**2,287**	**5,737**	**5,126**	**4,560**	**4,036**	**3,551**	**3,102**	**2,685**	**2,298**	**1,939**	**1,605**	**1,294**	**1,005**	**734**	**482**	**246**	**25**	**(183)**	**(378)**	**(561)**	**(735)**	**(898)**	**(1,053)**	**(1,201)**	**(1,341)**
Discount Factor	Full Year Discount @ 0.0565		1.0000	0.9465	0.8958	0.8479	0.8025	0.7595	0.7189	0.6804	0.6440	0.6095	0.5769	0.5460	0.5168	0.4892	0.4630	0.4382	0.4147	0.3925	0.3715	0.3517	0.3328	0.3150	0.2982	0.2822	0.2671	0.2528
Annual Net Present Value			(358,416)	2,165	5,140	4,346	3,659	3,066	2,553	2,111	1,729	1,401	1,119	876	669	491	340	211	102	10	(68)	(133)	(187)	(231)	(268)	(297)	(321)	(339)
Cumulative Net Present Value		**(338,064)**	**(358,416)**	**(356,251)**	**(351,112)**	**(346,765)**	**(343,106)**	**(340,040)**	**(337,487)**	**(335,377)**	**(333,647)**	**(332,246)**	**(331,128)**	**(330,251)**	**(329,582)**	**(329,091)**	**(328,751)**	**(328,540)**	**(328,438)**	**(328,428)**	**(328,496)**	**(328,629)**	**(328,816)**	**(329,047)**	**(329,315)**	**(329,612)**	**(329,933)**	**(330,272)**

NPV Conductor Analysis (in $k)
For 50 Years Ended December 31st, 2078

		2054	2055	2056	2057	2058	2059	2060	2061	2062	2063	2064	2065	2066	2067	2068	2069	2070	2071	2072	2073	2074	2075	2076	2077	2078	Terminal Value
Capital Expenditures		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Income Taxes *		982	903	831	765	703	647	595	548	504	464	427	392	361	332	306	281	259	238	219	201	185	170	157	144	133	894
Cost of Line Losses		(2,456)	(2,505)	(2,556)	(2,607)	(2,659)	(2,717)	(2,771)	(2,827)	(2,884)	(2,941)	(3,000)	(3,060)	(3,121)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	(3,184)	0
Net Impact to Ratepayers		**(1,474)**	**(1,602)**	**(1,724)**	**(1,842)**	**(1,955)**	**(2,070)**	**(2,176)**	**(2,279)**	**(2,380)**	**(2,478)**	**(2,574)**	**(2,668)**	**(2,760)**	**(2,852)**	**(2,878)**	**(2,903)**	**(2,925)**	**(2,946)**	**(2,965)**	**(2,982)**	**(2,999)**	**(3,013)**	**(3,027)**	**(3,040)**	**(3,051)**	**894**
Discount Factor	Full Year Discount @ 0.0565	0.2393	0.2265	0.2143	0.2029	0.1920	0.1817	0.1720	0.1628	0.1541	0.1458	0.1380	0.1307	0.1237	0.1170	0.1108	0.1048	0.0992	0.0939	0.0889	0.0841	0.0796	0.0754	0.0713	0.0675	0.0639	0.0639
Annual Net Present Value		(353)	(363)	(370)	(374)	(375)	(376)	(374)	(371)	(367)	(361)	(355)	(349)	(341)	(334)	(319)	(304)	(290)	(277)	(264)	(251)	(239)	(227)	(216)	(205)	(195)	57
Cumulative Net Present Value		**(330,625)**	**(330,988)**	**(331,357)**	**(331,731)**	**(332,106)**	**(332,483)**	**(332,857)**	**(333,228)**	**(333,595)**	**(333,956)**	**(334,311)**	**(334,660)**	**(335,001)**	**(335,335)**	**(335,654)**	**(335,958)**	**(336,248)**	**(336,525)**	**(336,789)**	**(337,039)**	**(337,278)**	**(337,505)**	**(337,721)**	**(337,927)**	**(338,122)**	**(338,064)**

ATTACHMENT 1 – HYDRO ONE'S LINE LOSSES MODEL – SCTL PROJECT – CONFIDENTIAL EXCEL

This model has been filed as a 'live' MS Excel spreadsheet and has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

OEB STAFF INTERROGATORY - 07

Reference:
Exhibit B-9-1, Pages 4-5

Preamble:
Hydro One states at the reference above that the bill impact of the costs of adding the required facilities to the network, line and transformation connection pools will cause a $0.14 per month decrease in a typical residential customer's bills under the RPP. The table on page 5 shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

Interrogatory:

a) Please confirm the consumption (kWh) per month that is assumed for the typical residential customer.

b) If the estimate does not assume a residential consumption of 700 kWh per month, please recalculate the table to reflect a residential consumption of 700 kWh.

c) For the value provided please provide the calculations showing how the monthly bill value was collected.

d) In the table provided on page 5 of the reference, please provide references as to how the values shown in rows B, C, D, and E were developed and calculated.

Response:

a) The consumption per month assumed for the typical residential customer is 750 kWh per month consistent with the OEB's direction on Page 57 of the Filing Requirements for Electricity Distribution Rate Applications (dated December 15, 2022)[1].

b) Hydro One is not aware of a change in any OEB requirements to calculate residential consumption using 700 kWh per month. Hydro One notes that the OEB issued *Defining Ontario's Typical Electricity Residential Customer 2023 Update* on December 13, 2023 that on page 4 reaffirms the consumption for a typical average residential customer is 750kWh/month. However, Hydro One has updated the table in response to the request.

[1] https://www.oeb.ca/sites/default/files/OEB-Filing-Reqs-Chapter-2-2023-Clean-20221215.pdf

A. Typical monthly bill	$143.39 per month
B. Transmission component of monthly bill	$15.44 per month
C. Line Connection Pool share of Transmission component	$1.50 per month
D. Transformation Connection Pool share of Transmission component	$5.06 per month
E. Network Connection Pool share of Transmission component	$8.89 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	-2.11%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	-2.18%
H. Impact on Network Connection Pool Provincial Uniform Rates	0.17%
I. Increase in Transmission costs for typical monthly bill (E x H)	$-0.13 per month or $-1.52 per year
J. Net increase on typical residential customer bill (I / A)	-0.09%

c) The typical monthly bill value (i.e., row A), is the total bill (before taxes and Ontario Electricity Rebate) for a typical medium density residential customer as of January 1, 2024, based on Hydro One's approved 2024 distribution rates[2] with approved 2024 RTSRs adjusted to reflect the 2024 Uniform Transmission Rates[3].

d) The values shown in rows B, C, D, and E were calculated as noted below.

- Row B = Row C + Row D + Row E
- Row C = (Adjusted RTSR Line and Transformation Connection Service Rate x (Monthly Consumption for Residential R1 * Loss Factor for Residential R1)) x (Line Connection UTR / Total of Line and Transformation Connection UTRs)
- Row D = (Adjusted RTSR Line and Transformation Connection Service Rate x (Monthly Consumption for Residential R1 * Loss Factor for Residential R1)) x (Transformation Connection UTR / Total of Line and Transformation Connection UTRs)
- Row E = Adjusted RTSR Network Service Rate x (Monthly Consumption for Residential R1 * Loss Factor for Residential R1)

[2] EB-2023-0030, HONI Application for 2024 Distribution Rates, Partial Decision and Rate Order, dated December 14, 2023.
[3] EB-2023-0222, 2024 Uniform Transmission Rates Update, Decision and Rate Order, dated January 18, 2024.

OEB STAFF INTERROGATORY - 08

Reference:

Exhibit B-7-1, Page 1

Preamble:

Hydro One states that overhead costs are charged through an ECI-EPC overhead capitalization rate for the line costs and Hydro One's standard overhead capitalization rate for the station costs.

Further, Hydro One states that Allowance for Funds Used During Construction (AFUDC) is calculated using the OEB's approved interest rate methodology to the Project's forecast monthly cash flow and carrying forward closing balances from the preceding month.

Interrogatory:

a) Provide additional details on how the overhead costs were calculated, with additional information on how they relate to ECI-EPC methodology.

b) Provide an explanation of the methodology used to determine the overhead costs as well as all calculations used to arrive at the stated values. Please provide the information in Microsoft Excel format.

c) Please describe how the overhead cost estimate shown in Table 1 and Table 2 for the Project compares to overhead cost estimates developed for similar Hydro One projects.

d) Please describe if there are any cost-savings achieved by Hydro One through the use of the ECI-EPC model.
   i. If yes, please show a detailed calculation of how these savings were determined and what methodology they were compared against.

e) Please also break down the cost differences between direct overheads and indirect overheads. If any of this cannot be done by Hydro One, please explain.

f) Provide an explanation of the methodology used to determine the AFUDC as well as all calculations used to arrive at the stated values. Please provide the information in Microsoft Excel format.

g) Please describe how the AFUDC cost estimate shown in Table 1 and Table 2 for the Project compares to AFUDC cost estimates developed for similar Hydro One projects.

Response:

a) Hydro One has calculated the overhead cost estimate using two capitalization rates, one for the line component that is employing the Early Contractor Involvement model with an external owners engineer that utilizes the ECI-EPC overhead capitalization rate, and another for the station component in which there is no early contractor involvement hence attracting the full Hydro One standard overhead capitalization rate. Overhead costs are applied to the direct costs as incurred applicable to the Project utilizing the respective overhead capitalization rate as described above. Further details on the calculation are provided in response to part b) below.

b) Please see response to part a) above for the methodology used to determine the overhead cost estimate. The calculation equation for each month is Direct Capital Expenditures in month multiplied by the applicable overhead rate. The results of the calculation of the overhead costs in Microsoft Excel format are provided in Attachment 1 of this Schedule.

c) The overhead cost estimate in Table 1 for the line work was developed utilizing the ECI-EPC overhead capitalization rate in a comparable manner to how the overhead cost estimates were developed for the Waasigan Project (EB-2023-0198). The overhead cost estimate in Table 2 for the station work was based on Hydro One's standard overhead capitalization rate utilized for Hydro One's non ECI-EPC capital portfolio (e.g., K4 Reconductoring Project (EB-2023-0197), Etobicoke Greenway Project (EB-2023-0199)).

d) Utilizing the ECI-EPC model does provide an enhanced overhead capitalization rate allocation, assuming that Hydro One's ECI-EPC overhead capitalization rate methodology is approved in a future revenue requirement application. This reduces the level of overhead to the Project in the magnitude of $20 million, as outlined in Table 1 below. Please refer to Exhibit I, Tab 1, Schedule 12, part j) for other benefits of using the ECI-EPC model.

Table 1 - Overhead Capitalization Rate Comparison

	As per B-07-01	Utilizing Standard Model Overhead from JRAP	$M Variance	% Variance
Materials	$ 29.9	$ 29.9	$ -	0.0%
Labour	$ 18.8	$ 18.8	$ -	0.0%
Equipment Rental & Contractor Costs	$ 125.2	$ 125.2	$ -	0.0%
Sundry	$ 5.2	$ 5.2	$ -	0.0%
Contingency	$ 28.0	$ 28.0	$ -	0.0%
Overhead	$ 6.4	$ 24.3	$ 17.9	277.1%
Capitalized Interest	$ 41.8	$ 43.9	$ 2.1	5.0%
Real Estate	$ 79.2	$ 79.2	$ -	0.0%
Total Line Work	$ 334.5	$ 354.4	$ 20.0	6.0%

e) As outlined in Exhibit B, Tab 7, Schedule 1, the overhead costs in Table 1 and Table 2 relate to only indirect overheads.

f) As disclosed in Hydro One's Joint Rate Application (EB-2021-0110), consistent with the OEB's Decision in EB-2008-0408 effective January 1, 2012, no AFUDC rate is specified for use by Hydro One. Hydro One was directed to base its interest capitalization rate on its embedded cost of debt used to finance capital expenditures. This is also consistent with Hydro One's adoption of United States Generally Accepted Accounting Principles (US GAAP) per the OEB's Decision in EB-2011-0268 for Transmission and US GAAP requirements for determination of interest capitalized. Results of the calculations for the AFUDC costs outlined in Table 1 and Table 2 of Exhibit B, Tab 7, Schedule 1, are provided as Attachment 1 to this Schedule.

g) There is no difference in the AFUDC methodology utilized in this Project relative to any other Hydro One project. The AFUDC methodology is consistently applied whether the project is delivered using an ECI-EPC or standard Hydro One delivery model. Any differences in total interest capitalized is a function of the interest rates at the time of construction versus prior periods and the expenditures on the Project.

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ATTACHMENT 1 – OVERHEAD AND AFUDC COST ESTIMATE CALCULATION – SCTL PROJECT

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 09

Reference:

Exhibit B-9-1, Pages 6-18

Preamble:

Hydro One has conducted a Net Present Value analysis on Network, Line and Transformation connection pools in addition to revenue requirements for each.

Interrogatory:

a) Please provide the following tables at the reference above in Microsoft Excel format:
   i. Table 1, p. 6
   ii. Table 2, p. 7
   iii. Table 3, p. 8
   iv. Table 4. p. 9
   v. Table 5, p. 10
   vi. Table 6, p. 11
   vii. Table 7, p. 12
   viii. Table 8, p. 13
   ix. Table 9, p. 14
   x. Table 10, p. 15
   xi. Table 11, p. 16
   xii. Table 12, p. 17
   xiii. Table 13, p. 18

Response:

a) Please refer to Attachment 1 to this Schedule for the requested Microsoft Excel format of Tables 1 to 13 presented in Exhibit B, Tab 9, Schedule 1. There are separate tabs for each of the tables referenced in the Microsoft Excel spreadsheet.

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ATTACHMENT 1 – TRANSMISSION RATE IMPACT ASSESSMENT TABLES – SCTL PROJECT

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 10

Reference:
Exhibit B-7-1, Page 3

Preamble:
At the above reference Hydro One states that they have entered into an agreement with a selected EPC contractor for the transmission line, with a Limited Notice to Proceed on early activities to advance contractors' long lead procurement process.

Interrogatory:

a) Please provide a copy of the agreement entered into between Hydro One and the selected contractor.

b) Please clarify whether the agreement with the selected EPC contractor only applies to transmission line construction or if station upgrades are included?
   i. If station upgrades are not included, how will a contractor be selected for these upgrades?

c) Are there any aspects of the project costs that Hydro One did not competitively tender? If so, why?

d) Please provide a list of early activities the contractor will be conducting that require a long lead procurement process.

e) Please clarify the scope of the Limited Notice to Proceed provided to the selected contractor.

f) Please provide details on how cost overruns will be handled between Hydro One and the selected contractor.

g) Does the agreement with the contractor provide for cost escalations and if so, what are the contractual provisions regarding escalation rates over the life cycle of the Project.

h) Please provide details on how the EPC contract with the selected contractor deals with risk assignment around aspects such as:
   i. Payment
   ii. Insurance
   iii. Recovery of Costs

Response:

a) The requested documents have been filed confidentially as Attachments 1 through 3 of this Schedule in accordance with the Board's Practice Direction on Confidential Filings. This is because content of the requested agreements contains commercially sensitive confidential information that is proprietary in nature. Public disclosure of this information will hinder Hydro One's competitive position in future competitive procurements or bids with other future potential contractors. Disclosure of confidential information could also prejudice the selected EPC contractors in future competitive procurements or bids or in subcontracting negotiations for the Project that is the subject of this proceeding.

b) The EPC contracts, as noted in Attachments 1 through 3 of this Schedule (Filed Confidentially), govern components of both the transmission line and stations.
   i. Not Applicable.

c) Given their nature, project cost aspects not competitively tendered were limited in scope and relate to activities such as land acquisition, landowner consultation programs, crop loss compensation, landowner legal fee reimbursement as well as internal labour, overhead and contingency required to manage the overall project. The majority of project costs were competitively tendered, including the EPC contracts for the line and stations.

d) Early activities undertaken by the Contractor that require a long lead procurement process include finalizing the preliminary design required for material procurement, securing production slots for fabrication of structures, and performing tests on finalized structures.

e) The scope of the Limited Notice to Proceed includes preliminary plans for execution, environment, access, quality and safety; geotechnical investigations and land surveys; preliminary design for structures; and early procurement of long lead items such as cables, steel structures, and foundations.

f) [redacted]

g) [redacted]

[redacted]

h) [redacted]

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ATTACHMENT 1 - EPC CONTRACT FOR SCTL PROJECT - CONTRACT 1

This attachment, in its entirety, has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

ATTACHMENT 2 - EPC CONTRACT FOR SCTL PROJECT - CONTRACT 2

This attachment, in its entirety, has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

ATTACHMENT 3 - EPC CONTRACT FOR SCTL PROJECT - CONTRACT 3

This attachment, in its entirety, has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

OEB STAFF INTERROGATORY - 11

Reference:
Exhibit B-7-1, Page 2

Preamble:
At the reference above Hydro One states that the Project cost estimate for the transmission line is based on a fixed price EPC contract.

Interrogatory:

a) Please provide a breakdown of the fixed price EPC contract by line costs and station costs.

b) What is the magnitude of the EPC contract as a percentage of the total Project cost?

Response:

a) A copy of this response has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings. [redacted]

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	
[redacted] [redacted]	[redacted]
[redacted] [redacted]	[redacted]
[redacted]	[redacted]

[redacted]

b) The EPC contracts, excluding interest and overhead, are forecast to represent approximately [redacted] of the direct costs or [redacted] of total project costs including interest and overheads.

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OEB STAFF INTERROGATORY - 12

Reference:
Exhibit B-7-1, Pages 2-3

Preamble:
At the reference above Hydro One states that the Project cost estimate for the transmission line is based on a fixed price EPC contract, and the selection of the EPC contractor used a two-stage process (known as the ECI-EPC methodology). The first stage was to utilize an external owners engineer and qualify EPC bidders based on experience and capacity to perform many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One. During the second stage, EPC contractors developed independent competitive proposals.

Interrogatory:

a) Provide a detailed description of the ECI-EPC methodology
   i. In the response please detail the specific steps taken in Stage 1 and Stage 2

b) Provide the criteria used to select the external owners engineer in Stage 1.

c) The reference above notes that “qualify EPC bidders based on experience and capacity to perform many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One.”
   i. Provide a list of the specific functions bidders were assessed on
   ii. Provide a quantitative analysis on how utilizing the successful contractor’s bid amount is more cost-effective than Hydro One performing the work itself.

d) During the ECI-EPC process, how many contractors were qualified under Stage 1?
   i. Please list all contractors that were considered qualified.

e) Provide the criteria used by Hydro One to evaluate the proposals received in Stage 2.

f) How many contractors submitted bids as part of Stage 2 of the process?

g) Provide the costs quoted by the proposals received in Stage 2 by each bidder and explain why the final proposal was selected.

h) Please provide a list of contractors who have previously been approved in Hydro One's LTC projects within the past 5 years and compare them to the contractors who have been approved in this project.

i) Is there any cost saving from using the ECI-EPC model to deliver the Project versus using the standard EPC delivery model that would be performed internally by Hydro One.
   i. If yes, please confirm whether the cost saving from using the ECI-EPC model is reflected in the total Project cost?
   ii. What other models besides the ECI-EPC methodology were considered in the process, and what are the costs associated with these models?

j) Please estimate the total project cost for the Project if the standard EPC delivery model was used.

k) Please explain advantages, disadvantages and risks associated with using ECI-EPC model vs the standard EPC delivery model performed internally by Hydro One in delivering large scale projects being added to Ontario's transmission system.

l) Please explain in detail what criteria Hydro One uses to decide whether the ECI-EPC model is appropriate for a particular transmission project?

m) What incentives or penalties are in place to encourage the ECI-EPC contractor to meet budgetary constraints and timelines?

Response:

a) The ECI-EPC model adopted by Hydro One for this Project is designed to involve the contractor into the development and design phases earlier than Hydro One's standard EPC model. Doing so is intended to provide a more efficient and effective approach as the Project proceeds through these stages and into the Project's construction phase. Continuity within these stages is particularly important for larger scale and complex projects such as the SCTL Project. Specifically, the ECI-EPC model provides the contractor greater involvement in the Project scoping, engagement with rightsholders and stakeholders, and evaluating risks and opportunities (including preparing potential solutions and mitigation measures) by having the contractor on board early in the development phase of a project. Early contractor involvement allows for better human resource allocation and allows Hydro One to utilize its internal resources in more efficient and effective ways. It also provides Hydro One with the opportunity to evaluate the EPC contractor's contributions and work relationship prior to entering into the more substantive construction contract. It enables tailoring contract terms appropriately and at a time that is advantageous to the project schedule. The ECI-EPC model introduces an opportunity for innovation in project design and execution while providing greater cost certainty through increased transparency and risk apportionment.

i. Further to what is outlined in Exhibit B, Tab 7, Schedule 1, in the first stage of the ECI-EPC process an external owner's engineer assists Hydro One with the qualification of EPC bidders based on experience and capacity to perform many of the development functions that under the standard Hydro One EPC delivery model would be performed internally by Hydro One. During the second stage, the EPC contractors actively participate in the project development activities, culminating in the development of independent competitive proposals for the construction phase of the project.

b) The owner's engineers were selected based on a combination of commercial and technical considerations including such items as: pricing, past performance, and their experience with ECI model and capacity to qualify EPC bidders and guide them through the development functions.

c)

i. The bidders were evaluated based on a combination of commercial and technical considerations including such items as: pricing, past performance on safety, approach to environmental management, project construction experience, engagement and inclusion of Indigenous businesses and workforces, and their experience and capacity to create a preliminary design and construction execution strategy to develop a competitive proposal that adheres to the Project need.

ii. The quantitative analysis requested cannot be provided. Hydro One uses the ECI-EPC model when the scale and complexity of a proposed project requires industry-tested expertise and innovation, increased transparency and prudency, and when risk sharing is warranted but not clearly defined at the onset of a project. To this end, once a determination is made to deliver the project using external vendors a quantitative assessment relative to Hydro One's internal delivery model is not performed as it would require a duplication of effort to develop the project with internal resources and external resources for a true comparison. This would be a redundant expenditure and may also confuse externally engaged stakeholders and rightsholders that would be approached twice for the same project. Delivering the project in the manner proposed is also cost effective as it enables Hydro One's resources to focus on its overall capital plan needs as described in part a) above.

d) Requests for proposals were sent to six contractors, from which two contractors were qualified in Stage 1 of the ECI-EPC process.

i. The contractors that were qualified for the SCTL Project were: Forbes Bros Ltd., and PowerTel Utilities Contractors Limited.

e) Proposals received in Stage 2 were evaluated based on a combination of commercial and technical considerations including such items as: pricing, capacity, technical competence to deliver the project, and past performance in delivering projects of similar size, scope and complexity.

f) The two contractors, qualified in Stage 1, submitted competitive bids as part of Stage 2 of the ECI-EPC process.

g) The costs quoted in the bids by the two contractors as part of Stage 2 of the process were: [redacted] (selected contractor) and [redacted] (other contractor), respectively. The successful bidder was selected based on an evaluation of the commercial and technical considerations as outlined in response to part e) above.

h) The list of contractors Hydro One has used in the past five years on LTC projects include:

- Valard,
- Aecon Power Services,
- Forbes Bros. Ltd.,
- McNally Construction Inc.,
- Black & McDonald,
- Eptcon Ltd.[1], and
- Taihan Electric USA Ltd.

The contractors selected for this Project, similar to previously chosen contractors, provide proven experience in delivering infrastructure projects and are resourced and equipped to address the challenges of the Project at hand.

i) Confirmed, there are potential cost savings from using the ECI-EPC model to deliver the Project versus using the standard EPC delivery model (i.e. absent early involvement).

i. Confirmed, the savings from the ECI-EPC model for the SCTL Project are included in the total Project cost forecast.
ii. No other model besides the ECI-EPC methodology were considered for the SCTL Project.

[1] Eptcon Ltd. is an affiliate of PowerTel Utilities Contractors Limited

j) The cost of the SCTL Project, absent the ECI-EPC model approach is not feasible to produce. To have developed the Project, and its corresponding cost estimate, under a standard EPC delivery model would have omitted required scope elements (i.e., consultation requirements on the engineering, design and construction planning).

These scope elements would then need to be fulfilled through alternative means, such as through additional subcontracts. In so doing, inefficiencies would reasonably result, such as added interface risk between contractors and a lack of understanding of the true magnitude of work required to execute the Project. This would then add risk cost to the Project overall. This is one of the benefits of having an ECI-EPC model during the development of a project of this magnitude and complexity. The resultant fixed price of the EPC is predicated on the knowledge the EPC garnered during the development phase of the project. A better understanding of the level effort to execute the project is developed.

The cost benefits from the efficiencies of the ECI-EPC model are embedded in the estimate and cannot be quantified. As such the resources and inefficiencies to undo the benefits expected to flow from the ECI-EPC is not available nor capable of being estimated with any level of certainty/accuracy. Therefore, a total project cost comparison between utilizing the standard EPC delivery model versus the use of an ECI-EPC model for the Project is not possible. At a minimum, Hydro One can offer that utilizing the ECI-EPC model does reduce the level of overhead to the Project, assuming that Hydro One's ECI-EPC OCR methodology is approved in a future revenue requirement application. The magnitude of this benefit is provided in Exhibit I, Tab 1, Schedule 8, part d).

k) Every project is unique and is assessed to determine an appropriate project delivery model. Sometimes a hybrid approach of internal and external resources reduces overall project risk or ensures the risk allocation is with the party best positioned to manage that risk, but no two projects are identical. Hydro One provides the following advantages and disadvantages of the ECI-EPC model:

<u>Advantages:</u> The ECI-EPC model utilized by Hydro One for this Project is designed to involve the contractor in the development and design phase earlier than Hydro One's standard EPC model. Doing so is intended to provide a more efficient and effective approach as the Project proceeds through these stages and into the Project's construction phase. Continuity within these stages is particularly important for larger scale and complex projects such as the SCTL Project. Specifically, the ECI-EPC model provides the contractor greater involvement in the Project scoping, engagement with rightsholders and stakeholders, and evaluating risks and opportunities (including preparing potential solutions and mitigation measures) by having the contractor on

board early in the development phase of a project. Early contractor involvement allows for better human resource allocation and allows Hydro One to utilize its internal resources in more efficient and effective ways. It also provides Hydro One with the opportunity to evaluate the EPC contractor's contributions and work relationship prior to entering into the more substantive construction contract. It enables tailoring contract terms appropriately and at a time that is advantageous to the project schedule. The ECI-EPC model introduces an opportunity for innovation in project design and execution while providing greater cost certainty through increased transparency and risk apportionment.

Disadvantages: The model requires that expenditures are incurred, and made to, the ECI-EPC contractor at an earlier stage of a project development cycle to compensate for their time and investment. This creates the risk that a potential write off will be greater if a project is delayed, requires re-engineered scope, or cancelled. There is often a time lag from the start of the ECI-EPC model to the start of construction. This time lag can result in a change of the availability of the EPC contractor's resources, which in turn could impact performance.

l) Hydro One uses the ECI-EPC model when the scale and complexity of a proposed project requires industry-tested expertise and innovation, increased transparency and prudency, and when risk sharing is warranted but not clearly defined at the onset of a project.

m) [redacted]

OEB STAFF INTERROGATORY - 13

Reference:

Exhibit B-7-1, Table 5, Page 11

Preamble:

Table 5 at the reference above shows the cost comparisons between the Wallaceburg TS, Chenaux TS and Parry Sound TS. The table is provided below for reference.

1 **Table 5 - Costs of Comparable Station Projects (Wallaceburg TS)**

Project	Chenaux TS	Parry Sound TS	Wallaceburg TS
Technical	Replace two 230/115kV 125MVA transformers and associated equipment, two 115kV breakers, new relay building, spill containment, drainage, and oil/water separator	Replace two 230/44kV 83MVA transformers and associated equipment, protection and control, spill containment, drainage, and oil/water separator	Install new 230 kV facilities, two 230/27.6 kV 83MVA transformers and associated equipment, protection and control, spill containment, drainage, oil/water separator and removal of existing 115 kV equipment and two existing buildings
Location	Eastern Ontario	Central Ontario	Southwest Ontario
Project Surroundings	Mostly rural	Mostly rural	Mostly rural
Environmental Issues	None	None	None
In-Service Year	2020	2023	2026
Estimate or Actual	**Actual**	**Actual**	**Estimate**
OEB-Approved Cost Estimate	N/A[20]	N/A[20]	–
Total Cost	**$45,036K**	**$24,156K**	**$48,900K**
Less Adjustments:			
Land Cost	*N/A*	*N/A*	*$100K[21]*
230kV Switching Facilities	*N/A*	*N/A*	*$2,106K*
Station Property Fence Line Expansion	*N/A*	*N/A*	*$2,271K*
Demolish/Removal Cost	*$2,016K*	*$587K*	*$1,190K*
Comparable Costs, before Escalation	**$43,020K**	**$23,569K**	**$43,233K**
Escalation Adjustment[22]	$11,737K	$4,203K	N/A
Total Adjusted Comparable Cost	**$54,757K**	**$27,772K**	**$43,233K**

Interrogatory:

a) Please provide a detailed calculation to show how the escalation adjustment values presented were determined for the Chenaux TS and Parry Sound TS.

b) The “Total Cost” for Wallaceburg TS is higher than both comparator projects. Please provide an explanation as to why this is the case.

Response:

a) Please see Table 1 and 2 below for the calculation of the escalation adjustment values, that underpin Table 5 in Exhibit B, Tab 7, Schedule 1, for the comparable projects - Chenaux TS and Parry Sound TS respectively.

Table 1 - Escalation Adjustment for Chenaux TS

End Period	Comparable Cost ($M)	Months Elapsed	Inflation Rate	Cost Escalation ($M)
Nov 30-2020	43.020			
year-end 2016	43.02	0	2.00%	-
year-end 2017	43.02	0	2.00%	-
year-end 2018	43.02	0	2.00%	-
year-end 2019	43.02	0	2.00%	-
year-end 2020	43.09	1	2.00%	0.07
year-end 2021	43.95	12	2.00%	0.86
year-end 2022	45.05	12	2.50%	1.10
year-end 2023	46.76	12	3.80%	1.71
year-end 2024	49.29	12	5.40%	2.53
year-end 2025	51.95	12	5.40%	2.66
Year-end 2026	54.76	12	5.40%	2.81
			Summation=	**11.737**
Opening Cost ($M)	43.020	A		
Escalation Adjustment ($M)	11.737	B		
Closing Cost ($M)	54.757	**C=A+B**		

Table 2 - Escalation Adjustment for Parry Sound TS

End Period	Comparable Cost ($M)	Months Elapsed	Inflation Rate	Cost Escalation ($M)
Oct 30-2023	23.569			
year-end 2016	23.57	0	2.00%	-
year-end 2017	23.57	0	2.00%	-
year-end 2018	23.57	0	2.00%	-
year-end 2019	23.57	0	2.00%	-
year-end 2020	23.57	0	2.00%	-
year-end 2021	23.57	0	2.00%	-
year-end 2022	23.57	0	2.50%	-
year-end 2023	23.72	2	3.80%	0.15
year-end 2024	25.00	12	5.40%	1.28
year-end 2025	26.35	12	5.40%	1.35
Year-end 2026	27.77	12	5.40%	1.42
			Summation=	**4.203**
Opening Cost ($M)	23.569	A		
Escalation Adjustment ($M)	4.203	B		
Closing Cost ($M)	27.772	**C=A+B**		

b) The “Total Cost” line item outlined in Table 5 of Exhibit B, Tab 7, Schedule 1 does not reflect the adjustments for project-specific requirements that are not comparable to the other projects. Hydro One adjusted the projects, in accordance with OEB’s Filing Requirements for Leave to Construct Applications that state “*to facilitate comparison, the applicant may adjust the costs of comparator projects to reflect key differences between them and the proposed project (e.g., different project scopes, additional complexities, real estate costs)*”. The “Total Adjusted Comparable Cost” presented in Table 5 demonstrates that Wallaceburg TS estimates falls within the range of cost for the comparator projects, Chenaux TS and Parry Sound TS.

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OEB STAFF INTERROGATORY - 14

Reference:
Exhibit E-1-1, Table 5, Pages 1-5

Preamble:
At the above reference, Hydro One states that the Project will require Hydro One to acquire land rights from 103 directly impacted properties, consisting of 95 privately held properties, 2 provincially held properties owned by OPG and 6 railway crossings. Hydro One is working with directly impacted property owners to negotiate amicable voluntary agreements, which may include full property buyouts, at the property owner's election. As of May 1, 2024, Hydro One has achieved voluntary early access agreements on approximately 95% of the properties that require new land rights. Additionally, as of May 1, 2024, 11 voluntary property settlement offers have been made, and 2 offers have been accepted.

Interrogatory:

a) Please provide an update on Hydro One's progress towards securing voluntary agreements with all affected landowners.

b) Please indicate when Hydro One anticipates securing the remaining voluntary agreements?

c) If Hydro One fails to secure voluntary agreements with all affected landowners, is it Hydro One's intention to seek expropriation allowances? If so, please describe the expropriation process Hydro One intends to follow as well as its timing. Please comment on whether the timing of securing voluntary agreements or seeking expropriation allowances could impact the construction schedule or in-service date.
    i. Please provide the total cost estimate related to potential expropriation activities for the proposed project.
    ii. Are the costs related to expropriation (including potential OEB proceeding) included in the costs estimate for the Project or will they be incremental to the project costs estimated in the Application?

d) OEB staff notes that under the "Resolution Approach" column, Hydro One states "Accommodate minor route refinements where and to the extent possible".
    i. Please define what a minor route refinement is and provide an example.

    ii. If applicable, please list any route refinements that have been proposed to landowners during negotiations and if any have been accepted.

Response:

a) Hydro One’s progress towards securing voluntary agreements with all affected landowners, as of August 20, 2024, is indicated in Table 1 below.

Table 1 - Land Acquisition Status (As of August 20, 2024)

Property Type	Number of Properties	Early Access Agreement Offered	Early Access Agreement Achieved	Voluntary Settlement Agreements Offered	Voluntary Settlement Agreements Achieved
Private Lands	95	100%	96%	73%	32%
Provincial Lands (OPG)	2	100%	100%	Pending	Pending
Railway Lands	6	N/A	N/A	Pending	Pending

b) The completion of Hydro One’s voluntary land rights acquisition is dependent upon landowner-specific circumstances. Hydro One’s voluntary land rights acquisition will continue post-Leave to Construct approval under the following framework: if Leave to Construct approval is granted on satisfactory terms and conditions, shortly following this determination, Hydro One will provide written notice to all remaining outstanding landowners of its intention to seek expropriation relief under s.99 of the Act within a short, prescribed period. The need to adopt the shortest time periods and proceed expeditiously with s.99 relief is directly attributed to the overall need and timing to complete construction and in-servicing of this Priority Project.

In the written notice described above, Hydro One will emphasize that after it has filed its s.99 Application with the OEB, the incentives found in the voluntary land acquisition program will no longer apply. The land rights acquisition for the outstanding required land rights will thereafter follow the legislative process and compensation will be determined based on the prevailing legislative standards.

c) As stated in the response to part b) above, if Hydro One is unsuccessful in securing 100% of the land rights required via voluntary agreements, shortly after having received OEB Leave to Construct approval Hydro One will seek expropriation authority in accordance with s.99 of the OEB Act.

The timing of Hydro One's land acquisition program has been incorporated into the overall project schedule; however, expropriation has not been, as defined in Exhibit B, Tab 11, Schedule 1.

i. The total cost estimate for expropriation is dependent upon how many landowners choose not to pursue voluntary settlements and instead proceed through to the expropriation process.

ii. Hydro One's risk registry considers the expropriation risk and the total project cost estimate accounts for this risk by including an allowance based on probabilistic modelling within the Project's contingency.

d) To clarify, “Accommodate minor route refinements” is not an identified “Resolution Approach” in Exhibit E, Tab 1, Schedule 1, Table 2. The general route of the project has been completed with the Final ESR submitted to the MECP on February 5, 2024.

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OEB STAFF INTERROGATORY - 15

Reference:

Exhibit G-1-1, Table 5, Attachment 1, Page 3

Preamble:

At the above noted reference, the Customer Impact Assessment (CIA) states that the "CIA is concerned with the potential impact of the above project on transmission connected customers in the area."

Further, the report states, "the following potential impacts on existing customers in the area are reviewed is this CIA:

- Short circuit impact
- Impact on customer power supply reliability."

Interrogatory:

a) Describe specific measures Hydro One has implemented to address these concerns.

b) Describe any feedback Hydro One has received from affected customers and how Hydro One has responded.

c) Provide information related to any stakeholder sessions Hydro One will conduct to ensure affected customers are aware of how these concerns will be addressed.

Response:

a) To clarify, the word "concerned" as used in the CIA (and noted in Preamble above) was intended to mean that the CIA **assesses** the potential impact of the above project on transmission connected customers. This language is provided in this customer facing document to clarify the limits of the CIA's assessment and to delineate between the objective of the CIA from that of the System Impact Assessment ("SIA"). Specifically, the CIA assesses the short circuit impacts and impacts on customer power supply reliability; whereas the SIA involves an assessment of voltage performance and loading capability of the transmission facilities in the area.

The findings reached in the Final CIA report relative to this assessment are:

- With the incorporation of SCTL, the short circuit levels observed at all connection points remain within the limits of the Transmission System Code with the Lambton TS 230 kV bus in split mode of operation; and

- The addition of SCTL will improve the power supply reliability for customers in the region, including the beneficial impact of converting Wallaceburg TS from 115 kV supply to 230 kV supply.

Given this, Hydro One has not taken any specific measures in addition to or outside of what is described in the CIA regarding how Hydro One will be managing its operations.

b) Hydro One received the following feedback from area customers:

Feedback	Hydro One Response
Requested extension on the comment period.	Hydro One granted the customer a 10-day extension for comments.
Does Hydro One expect customers to make changes to existing connections such that new fault levels can be accommodated?	Each customer is to take action, at its own expense, to upgrade its facilities as may be required to accommodate new available fault current level up to the maximum allowable fault levels as set out in the OEB’s Transmission System Code - Appendix 2. All fault levels associated with this project are within the Transmission System Code limits prescribed in Appendix 2.
The report refers to Lambton TS operating in split mode which is a division of the bus to manage the short circuit levels. Splitting the bus can make the system more vulnerable to disruptions and faults in one section affecting the other section(s), would this impact our operations? Operating in split mode may limit the flexibility to respond to changes in generation, would this have an impact on our operations?	Operation of Lambton TS in a bus split mode will not have any impact on this and other customers’ operation. The station was operated in this mode in the past for short circuit mitigation.
Customer requested clarification on transmission circuit nomenclature changes as a result of the completion of Lakeshore TS.	Clarification was provided to the customer on the changes to circuit nomenclature.
Customer requested additional clarity on short circuit results	Provided customer clarity on short circuit results and values.

c) Given the nature of the feedback detailed in part b) no further response were deemed required.

ENBRIDGE GAS INC. - 01

Reference:
Hydro One Networks Application, Exhibit C-1-1, Page 2

> "*230kV-rated XLPE underground cables and accessories, including new concrete encased duct banks, will be used between the south gantry at Lambton TS and the first 230 kV double-circuit dead-end tower structure (approximately 400 m in length) due to clearance concerns with the overhead lines. To facilitate the connection between the overhead conductor and underground cable, transition terminals will be installed close to the first 230 kV double-circuit dead-end tower structure and the Lambton TS bus structure within the station. Pipelines owned by other operators inside the ROW will continue to operate without disruption as crossing agreements and safety buffers will be put in-place*."

Interrogatory:

a) Please confirm the minimum offset that Hydro One will have in place between the powerline tower footings and other energy infrastructure in the area of these footings.

b) Please provide copies of all crossing agreements currently in place.

Response:

Preface: Hydro One notes the reference to this interrogatory question misquotes, the evidence found in Exhibit C, Tab 1, Schedule 1, Page 2. Specifically, Exhibit C, Tab 1, Schedule 1 does not state "*Pipelines owned by other operators inside the ROW will continue to operate without disruption as crossing agreements and safety buffers will be put in-place*". Hydro One expects crossing agreements and safety buffers will be executed and implemented prior to and during construction. Hydro One cannot comment on whether third party pipelines will make operational determinations on whether their facilities may or may not operate during Project construction. Hydro One intends to work collaboratively to minimize outages, where practicable, and recognizing public safety as the highest priority.

a) A minimum offset of 20 meters will be applied for all permanent structure footings from the edge of infrastructure right-of-way.

b) No crossing agreements have yet to be completed to date with Enbridge Gas Inc. Such subsequent crossing agreements will be pursued with Enbridge Gas Inc. upon finalized engineering and design.

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ENBRIDGE GAS INC. - 02

Reference:

Hydro One Networks Application, Exhibit F-1-1, Page 6

> "*System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, and load security in accordance to the Ontario Resource and Transmission Adequacy Criteria (ORTAC) and in line with applicable reliability standards.*"

Interrogatory:

a) Please confirm that Hydro One will be undertaking an AC Mitigation study with respect to the proposed transmission line project.

b) Please provide details of the timeline and progress to date associated with AC Mitigation study.

c) Please confirm that if the AC Mitigation study recommends additional mitigation installed on Enbridge Gas assets, costs associated with the installation of this mitigation will be paid by Hydro One.

Response:

a) Confirmed. Hydro One will be conducting an AC Mitigation study with respect to the proposed transmission line.

b) Hydro One has engaged a third-party service provider who will conduct the AC Mitigation study. To date, site surveys have been completed, and a request for information process is ongoing with individual pipeline owners. Hydro One anticipates completing the AC Mitigation study report in Q4 2024 and will then share this report with individual pipeline owners.

c) Confirmed. If any additional mitigation is required, the associated costs will be paid by Hydro One.

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KEVIN JAKUBEC - 01

Reference:

In the matter of the Ontario Energy Board Act,1998, S.O. 1998, c.15. Schedule B, as amended (the “Act”). In the matter of an application by Hydro One Networks Inc. pursuant to sections 92, 96.1 and 97 of the Act for an Order or Orders granting leave to construct the St Clair Transmission line route, approximately 64 kilometres of electricity transmission line and associated facilities from Lambton Transformer Station connecting Wallaceburg Transformer Station and terminating at the Chatham Switching Station in Chatham -Kent Ontario.

Written Interrogatories from Kevin Jakubec

Pursuant to the OEB’s Procedural Order No 1 dated July 31,2024, Kevin Jakubec submits the following Interrogatories:

Interrogatory:

Risk Identification of Environmentally Sensitive Aquifer along the St Clair Transmission line route;

Given the connection between water poverty and energy poverty and the grave financial hardships that can result to rate users should water wells become interfered either in quantity or quality through the construction of the St Clair Transmission line route I ask the following Interrogatories to determine if the Applicant has properly recognized and taken adequate mitigation, remediation and compensation measures for a historically known environmentally sensitive area along the St Clair Transmission route where the underlying Aquifer and water wells are sensitive to construction activities.

Specifically from a Hydro One Networks presentation to Chatham-Kent Council on February 5th, 2024 that was recorded can the Applicant provide the following information;

All seismic studies from helical pile driving from the Chatham to Lakeshore project that the Applicant has informed Chatham-Kent Council is relied upon for the St Clair Transmission line project including vibration records comparing water well pump vibration to helical pile driving vibrations.

All Geotechnical reports for the St Clair Transmission line project including depth profile mapping of the variable Aquifer depth along the St Clair Transmission line route.

All background seismic studies characterizing the existing background vibration field generated from the installed windfarms that the St Clair Transmission line route must transverse.

All studies, expert opinions and communications sent to the MECP Ontario Ministry of Environment Conservation and Parks where the Applicant has discussed the issue of a groundwater baseline study for the St Clair Transmission line project.

Blasting plan for the use of explosive splicing that the Applicant will use for the St Clair Transmission line project and if the Blasting plan has recognized the Environmentally Sensitive Aquifer area along the transmission route and if any precautions are so noted in the Blasting plan.

All vibration suppression plans and designs for the Transmission towers that will be used in the Environmentally Sensitive Aquifer area, specifically how will the transmission towers not contribute to or minimize vibration transmission.

Remediation and Compensation Plans to impacted rate users whose water wells would be interfered by the construction of the St Clair Transmission line project:
What remediation efforts will the Applicant make towards rate users whose water wells are negatively impacted to make the rate users drinking water supply whole again? Will the Applicant provide a suitable safe drinking water supply in sufficient quantity for household and any livestock needs?

In terms of compensation for causing environmental stigma to the rate user's property should the water well no longer be usable to provide water in the same safe manner before construction of the St Clair Transmission line project, will the Applicant fully financially compensate the rate user for Environmental stigma damages?

<u>Response:</u>
The studies requested in this interrogatory relate to environmental assessment matters. In Hydro One's view, they do not directly relate to the matters in issue in this proceeding, namely, electricity price, electricity reliability or the quality of electricity service as set out in Procedural Order No. 1.

In support of this view, Hydro One is mindful that the requested information subject-matter pertains to the environmental assessment that is governed by the Ministry of Environment, Conservation and Parks ("MECP").

For example, the Final Environmental Study Report ("ESR") for the Project provides a summary of the environment, including groundwater resources, in Section 4.6.4. Hydro One provided a formal response to MECP's comments on the issue of groundwater and use of helical piles (i.e., MECP's comment #9) as noted in Section 3.13.1 of the Final ESR. All correspondence with the MECP throughout the Class EA is summarized in Section

3.7.14 of the Final ESR, and the Record of Consultation logs are included in Appendix B6 of the Final ESR.

As per Section 7.7.6 of the Final ESR, Hydro One has committed to the use of helical (screw) pile foundations for the transmission line structures. This means that the foundations installed for the Project will remain within the protective clay overburden between approximately 10 meters to 30 meters (depending on the depth of the overburden at each specific structure location) above the top of the contact aquifer layer. The helical pile foundations used for the Project will be installed by rotating the steel pile slowly into the ground. Helical pile foundations also do not have the vibrations associated with driven steel piles.

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SISKINDS FIRM GROUP - 01

Reference:
PROJECT ALTERNATIVES
1. Assessment of Project Alternatives

Reference: EB-2024-0155 – Hydro One Networks Inc. ("Hydro One") Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit B-5-1.

Interrogatory:

a) We ask for a detailed review, analysis and comparison of any alternative solutions that were considered, including series capacitor alternatives, distribution solutions, or other transmission solutions. Provide an explanation as to why the proposed project selected as the preferred option? What, if any, distinctions were noted by Hydro One and identified between the various alternatives in terms of their ability to meet the capacity needs of the proposed project?

b) Was the route selected by Hydro One the least expensive alternative?
   i. Did the Class EA findings confirm that the preferred route?
      1. What factors were taken into consideration by Hydro One to reconcile the increased cost to ratepayers with the socio-considerations and potential socio-economic impacts?

      2. What factors were taken into consideration by Hydro One to reconcile the increased cost to ratepayers with the impacts to the natural environment?

c) In terms of consideration of the various alternatives, Hydro One indicates that the selected route utilizes approximately 80% of the existing transmission corridor lands to minimize impacts to the natural and socio-economic environments, is the selection of the preferred route as opposed to the least expensive alternative based on the findings set out in the Class Environmental Assessment?
   i. If yes, how does Hydro One reconcile the increased cost to ratepayers with the socio impact considerations?

   ii. What steps are taken by Hydro One to minimize and/or mitigate the impacts to the socio-economic environment?

Response:

a) To clarify, the IESO is responsible for assessing how the various alternatives meet the need of the Project. Please refer to Exhibit I, Tab 5, Schedule 1, part a) for details pertaining to the analysis and selection of the proposed Project.

b) Please refer to Exhibit I, Tab 5, Schedule 1, part b).
   i. Yes, the Class EA findings confirm that the proposed Project route is the preferred route.
      1. Please refer to Exhibit I, Tab 5, Schedule 1, part b)ii.
      2. Please refer to Exhibit I, Tab 5, Schedule 1, part b)ii.

c) Yes, the preferred route is based on the findings set out in the Class EA.
   i. Please refer to Exhibit I, Tab 5, Schedule 1, part b)ii.
   ii. Hydro One completed a Final ESR on February 5, 2024 as detailed in Exhibit B, Tab 1, Schedule 1. Section 7 of the Final ESR describes the mitigation measures committed by Hydro One to address environmental effects of the Project, including mitigation measures for effects to the socio-economic environment.

SISKINDS FIRM GROUP - 02

Reference:
PROJECT COST
2. Compensation Payments

Reference: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Hydro One

Interrogatory:

a) Hydro One has updated the Compensation and Incentive Agreements for both Easement and Fee Simple circumstances, has consideration been given by Hydro One for an annual payment to the landowner, similar to natural gas pipelines and transmission towers, for the continued and ongoing impacts associated with Hydro One's use of the land?

b) Hydro One indicates that all agricultural lands taken out of production and crops lost arising from the project's construction activities will be compensated in accordance with Hydro One's crop loss / crop lands out of production policies. Have similar policies been adopted for any continuing and ongoing payments arising for those agricultural lands taken out of agricultural production due to the project?

Response:

a) Hydro One's land rights acquisition program, and compensation associated, is consistent with previously approved applications. Annual payments are not being offered by Hydro One as part of the land rights acquisition program for the Project. Hydro One is compensating landowners for the necessary land rights it requires for its assets via a one-time payment framework with most applicable funds being compensated to landowners at the time of the legal registration/closing of a transaction. This methodology is consistent with how other long term industry infrastructure companies (e.g., municipalities, other electrical transmission and distribution companies, etc.) approach their land rights compensation in the Province. This compensation framework provides property owners with fair and reasonable compensation for the land rights being acquired based on market value, while providing Hydro One with the security of rights necessary to construct, operate and maintain the transmission line infrastructure that forms an integral part of the electricity network in the Province.

b) Please refer to Exhibit I, Tab 5, Schedule 9, part b).

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SISKINDS FIRM GROUP - 03

Reference:

LANDOWNER AGREEMENTS

3. Easement Language and Other Business Ventures

Reference: EB-2024-0155 – Hydro One Networks Inc., Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit E-1-1, Form and Transfer of Grant of Easement.

Interrogatory:

a) What is the purpose of the broad language and scope of the statutory easement language proposed by Hydro One. We seek clarification with respect to the specific rights Hydro One intends to exercise under this easement, specifically relating to:
   i. Access rights for maintenance, repair, and emergency purposes;
   ii. Restrictions on landowners' use of the land within the easement area;
   iii. Removal, relocation, and reconstruction;
   iv. Provisions for compensation for any business or property loss resulting from Hydro One's use of the easement.

b) The easement language proposed by Hydro One has been broadly drafted to grant Hydro One broad rights to replace, enlarge, move, relocated the proposed project creating uncertainty with the landowners relating to the current and future impacts on the property. Is this overly broad scope in the grant of the easement required or necessary for the project approval being applied for?

c) Can Hydro One confirm its position that if there is further work required on the easement lands that either require regulatory approval or result in further impacts to the easement lands that there will be no further compensation paid to the landowners? Has consideration been given by Hydro One to future potential payments to the landowners for those impacts associated with any future work undertaken on the lands by Hydro One?

d) The Transfer and Grant of Easement provides Hydro One or alternatively "a related business venture" the right to use the lands for telecommunications systems appears to grant a use of the lands to Hydro One that is not currently being proposed, contemplated or subject to review.
   i. What business ventures are being contemplated by Hydro One, or alternatively permitted through the Transfer and Grant of Easement language being proposed by Hydro One?

ii. What economic modelling has been completed, if any, for those related business ventures, including potential revenue, operational costs? Specifically, what types of related business ventures are being contemplated and/or permitted?
iii. Please provide details of the authority that Hydro One is relying upon to request that the OEB grant approval for the additional and unrelated activities being considered with the construction contemplated by the Applicant.
iv. Under what circumstances will the landowners receive compensation from the construction of any related business ventures undertaken by Hydro One?
v. What regulatory authority is Hydro One relying upon to expand its use impacting the landowner's use and enjoyment of their land without providing any additional compensation to the landowner for the additional impacts resulting from any other business ventures or unrelated activities conducted on the property by Hydro One?
vi. Are there any circumstances under which Hydro One would agree to limit or place conditions on its easement rights?

Response:

a)

i. Please refer to Exhibit I, Tab 5, Schedule 8, part a i).
ii. Please refer to Exhibit I, Tab 5, Schedule 8, part a ii).
iii. The right to remove, relocate, and reconstruct the transmission line facilities within the right of way / easement as deemed necessary by Hydro One in order to allow for the safe, secure and reliable operation of the transmission line.
iv. Please refer to Exhibit I, Tab 5, Schedule 8, part a iii).

b) Please refer to Exhibit I, Tab 5, Schedule 8, part b).

c) Please refer to Exhibit I, Tab 5, Schedule 8, part c).

d)

i. Please refer to Exhibit I, Tab 5, Schedule 8, part d i).
ii. Please refer to Exhibit I, Tab 5, Schedule 8, part d ii).
iii. Please refer to Exhibit I, Tab 5, Schedule 8, part d iii).
iv. Please refer to Exhibit I, Tab 5, Schedule 8, part d iv).
v. Please refer to Exhibit I, Tab 5, Schedule 8, part d i) and iv).
vi. Please refer to Exhibit I, Tab 5, Schedule 8, part e).

SISKINDS FIRM GROUP - 04

Reference:

IMPACT ON AGRICULTURAL OPERATIONS

4. Agricultural Operations

Reference: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit E-2-1.

Interrogatory:

a) Several of the affected properties are currently used for viable agricultural production, what if any steps, are being taken by Hydro One to minimize and mitigate any disruption to the existing agricultural operations during the construction activities, operational period, and decommissioning stages of the project?

b) Has Hydro One given any consideration to compensating landowners on an annual basis for the ongoing and continued loss of agricultural production, and/or increased and continuing operational losses, and/or any other impacts arising from the project?

Response:

a) Please refer to Exhibit I, Tab 5, Schedule 9, part a) with respect to the construction and operational period. As noted in Exhibit I, Tab 5, Schedule 9, part c) there are currently no decommissioning plans for this new transmission line, and as such no mitigation measures are contemplated at this time. It is often the case that electricity transmission lines and structures will have an expected service life of over 80 years.

b) Landowners will be able to continue agricultural activities within the corridor post-construction. Hydro One recognizes there may be unique or exceptional circumstances that may exist that require further compensation for lands out of production. These unique and exceptional circumstances will be identified and determined in consultation with the impacted landowner and appropriate compensation will be advanced where reasonable.

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SISKINDS FIRM GROUP - 05

Reference:

ENVIRONMENTAL AND COMMUNITY IMPACT

5. Environmental Assessment and Mitigation Measures

Reference: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Environmental Study Report (ESR), Exhibit F-1-1.

Interrogatory:

a) Hydro One has completed an Environmental Assessment (EA) for the project. Please provide an overview of the findings of the EA as it relates to the effects identified on the agricultural resources including impacts on the agricultural operations and future maintenance effects to farmland, movement of farm machinery and agricultural building removal within the easement / right-of-way.

b) Has Hydro One prepared any operational policies, plans, or guiding documents either adopted or proposed relating to the replacement or removal of any Hydro One infrastructure when it is no longer required.

c) What polices have been implemented by Hydro One to ensure that the mixing of soil and movement of soil will not detrimentally impact existing agricultural lands?

d) What, if any, measures are being proposed by Hydro One with respect to ensuring that any impediments to farm vehicle maneuverability will be mitigated and minimized?

e) During what periods is Hydro One proposing to conduct its construction activities to avoid any sensitive times of year with respect to agricultural operations? What specific circumstances are deemed by Hydro One not to feasible to avoid construction and maintenance activities at sensitive times of the year?

f) For those areas identified by Hydro One as requiring larger areas, beyond the individual tower footings, what specific mitigation measures are being proposed to minimize the impacts and retain as much land as possible in agricultural production?

Response:

Hydro One is unclear how this question pertains to the issues and directions provided in Procedural Order No. 1. This interrogatory relates to matters within the purview of the Class EA process and does not pertain to issues of electricity price, electricity reliability and the quality of electricity service. That said, and to assist landowners participating in this proceeding Hydro One provides the following information.

a) The preferred route will cross several agricultural property parcels. Some effects to agricultural operations will be long-term and result in net effects (that are not anticipated to be significant), however, many are temporary in nature and can be mitigated with diligent construction planning and implementation of mitigation measures during construction as described in Section 7.1 and Table 7-1 of the Final ESR.

   Where practical and technically feasible, the location of towers will be placed to minimize impacts to maneuverability of agricultural equipment (e.g., along lot lines or field boundaries). The need to remove agricultural improvements was a consideration included in the route evaluation to determine the preferred route. Any required improvements removals will follow the compensatory principles described in the Land Acquisition Compensation Principles for the Project. Compensation for situations where there is contemplation of agricultural improvement removal will depend on whether voluntary agreements are executed by a property owner or expropriation authorization is required. If expropriation authorization is required, it will follow the compensation requirements under the legislative model.

b) No. Decisions relating to the replacement or removal of Hydro One infrastructure when it is no longer required, is assessed and informed on a case-by-case basis via established Regional or Bulk planning processes and consistent with good utility practice standards. This approach considers specific asset conditions, system conditions, or specific customer needs with a view to minimizing operational costs and leveraging existing rights-of-way, where practical.

c) Hydro One recognizes that the mixing of soil and the movement of soil between property parcels is a potential effect of the Project. As per Section 7.1.3 of the Final ESR, contractors will minimize stripping or excavation of soils to the extent practical, and where soil stripping is required both topsoil and subsoils will be removed and stockpiled separately. The depths of soil being removed will be carefully monitored and minimized during stripping activities, while the volume of topsoil and subsoil salvaged for replacement or re-use on site will be maximized, where practical. Soils will be stripped under generally dry conditions (not saturated), such that rutting, soil mixing, or other undesired ground disturbance is minimized to the extent practical and vegetation, stone piles, fencing and deleterious materials will be removed prior to stripping. For backfilling operations, topsoil and subsoil will be replaced in reverse order of excavation to minimize the potential for additional mixing and maximizing future growing potential. Soil cover on exposed areas within agricultural areas will be discussed with the landowner for the most appropriate solution.

Additionally, the EPC contractor will utilize helical piles which will minimize surface disturbance and does not require soil excavation or soil stripping.

Equipment inspections, vehicle inspections and cleaning will be conducted as required during construction, to minimize the potential for inadvertent transport of trace soils between contaminated and non-contaminated agricultural fields. Once temporary construction access has been installed, there should be minimal direct contact between construction vehicles and agricultural soils. Cleaning will be conducted using a risk-based approach, whereby vehicles and equipment that have come in contact with soils will be inspected and cleaned of dirt/debris/seeds and cleaning will occur in a manner that ensures that runoff is contained, and waste materials can be collected.

Finally, any imported topsoil will be tested for soybean cyst nematode ("SCN") or otherwise shown to be free of SCN.

d) Where practical, the location of towers will be placed to minimize impacts to maneuverability of agricultural equipment (e.g., along lot lines or field boundaries). Continued engagement with individual property owners impacted by the Project is ongoing which includes consultation on design components (i.e., tower placements).

e) To construct the transmission line, it is necessary to transport construction equipment and labor to each structure location and also locations within and outside the right of way in order to pull and place wire on transmission structures. To do this with minimal impact to farmlands, building access roads along the right-of-way and in some cases outside the right-of-way is required. The inherent nature of transmission line construction causes disturbance to farming operations and so it is imperative to complete construction, remove the access roads and reclaim the lands to its original state as soon as possible. For this reason, it may be necessary to carry out construction without intermittent breaks for sensitive agricultural production times of year. Hydro One mitigates this impact by providing compensation to the landowners for loss of agricultural production. If work is required outside of the workspace or laydown areas, and landowner concerns arise regarding timing, these concerns will be discussed and addressed on a case-by-case basis to determine whether timing restrictions, or other mitigation measures, may be implemented without impairing overall construction timing and schedule.

f) As a part of the construction execution plan, the means and methods by which equipment and labour are transported to each tower location and to the strategically placed locations for pulling the wire are planned with the intention to minimize the impacts and retain as much land as possible in agricultural production. As explained in response to part (e) above, construction is planned to be executed with the shortest possible duration without intermittent breaks to reclaim the lands to its original state as soon as possible.

THE ROSS FIRM GROUP - 01

Reference:

PART II: Project Alternatives

1. Assessment of Project Alternatives

Reference #2: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit B-5-1.

Interrogatory:

a) Please provide detailed analysis and comparison of any alternative solutions that were considered, including series capacitor alternatives, distribution solutions, or other transmission solutions. Why was the proposed project selected as the preferred option?

b) Was the route selected by HONI the least expensive alternative?
   i. If not, what is the budget difference between the selected route and the least expensive alternative?
   ii. Is the selection of the preferred route as opposed to the least expensive alternative based on the Class EA findings?
      1. If so, how does HONI reconcile the increased cost to rate payers with the environmental considerations?

Response:

a) The detailed analysis and comparison of any alternative solutions to the Project are detailed in the IESO's Bulk Planning Report dated September 23, 2021, entitled "*Need for Bulk System Reinforcements West of London*". The document is provided as Exhibit H, Tab 1, Schedule 1, Attachment 2. This document underpins the Orders in Council, provided at Exhibit B, Tab 3, Schedule 1, Attachments 1 and 3, that establish that the Project is not only needed, but also used as justification for the Project to be designated by the Government of Ontario as a Priority Project.

   The rationale for why transmission was the preferred option is not an issue in this proceeding as detailed in Procedural Order 1 and pursuant to section 96.1 (2) of the OEB Act. As noted in Procedural Order 1, the OEB has stated that need for the Project has already been determined and is not an issue or consideration in this proceeding.

b) Early cost estimates of the route alternatives were not required for the route evaluation conducted as part of the Class EA; rather, a number of Technical and Cost criteria were applied to assess cost-influencing factors (such as total line length, number of angles, etc.) resulting in a relative comparison of the route alternatives on this basis. The Technical and Cost criteria represent one of the four evaluation categories (i.e., 25% of the total route evaluation); although other evaluation categories (such as Natural Environment and Socio-Economic Environment categories) contain criteria which may also influence cost (e.g., through requirements for additional environmental surveys or permits). While Route Alternative 2 (as well as Route Alternatives 3 and 4) require the conversion of the Wallaceburg TS from 115 kV to 230 kV and involve some additional effort to remove the existing N5K transmission lines and structures, these costs are largely offset by refurbishment costs that would otherwise be required for the 115 kV transmission line. Additionally, the conversion of Wallaceburg TS from a single-circuit 115 kV supply to a double-circuit 230 kV supply would result in improved reliability and efficiency of the transmission system supply to the Wallaceburg area. The process used to identify and evaluate alternative routes is detailed in Section 5 of the Class EA filed with the MECP. Hydro One does not view 'least cost' to always be synonymous with the best solution (i.e., preferred route). Hydro One is required to consider other factors that take into account natural, social, cultural and economic environmental factors when evaluating route alternatives for transmission lines. Overall, Route Alternative 2 was selected as the preferred route, as it was the most preferred alternative across the three evaluation criteria (Natural Environment, Socio-economic, and Indigenous Culture, Values and Land Use). Additionally, the preferred route did not rank the least preferred in any one of the criteria, unlike all other route alternatives. These results are detailed in Table 5-13 of the Final ESR. Further details are provided in Exhibit I, Tab 1, Schedule 2.

i. As outlined in response to part b) above, early cost estimates of the route alternatives were not required for the route evaluation, thus it is not possible to provide a budget difference.
ii. The selection of the preferred route was based on the Class EA findings. As detailed in the Final ESR, overall the preferred route minimizes the overall impact to the Natural and Socio-Economic Environments criteria, as compared to the other route alternatives and minimizes impacts to agricultural lands by utilizing existing transmission corridors for approximately 80% of its total length. From an Indigenous Culture, Values and Land Use perspective, the preferred route avoids a separate crossing of the Thames, North Sydenham and Sydenham Rivers, minimizes impacts to native habitats and natural or naturalized areas which support hunting and harvesting activities, and provides improved transmission reliability to an Indigenous community supplied from the Wallaceburg TS. From a real estate perspective, the preferred route maximizes the ability to utilize existing transmission corridors. This route also results in improvements to the reliability and efficiency of the transmission system supply to the Wallaceburg area through an upgrade to the Wallaceburg TS. Furthermore, the cost impact to ratepayers of the

Project, as detailed in the prefiled evidence at Exhibit B, Tab 9, Schedule 1, is a reduction of $0.14/month for a typical residential customer's bill. Thus, on balance, Route Alternative 2 is the preferred route to complete the Project as detailed in the Final ESR that has been reviewed and completed with the MECP.

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THE ROSS FIRM GROUP - 02

Reference:
PART III: Project Cost
2. Cost Estimates and Reasonableness

Reference #3: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit B-7-1.

Interrogatory:

a) Has Hydro One provided sufficient information to demonstrate that the estimates of the project cost are reasonable?

b) How do these cost estimates compare to other similar projects undertaken by Hydro One or comparable projects elsewhere?

c) Are the proxies used for comparison appropriate and sufficient for this Project?

Response:

a) Yes.

b) Please refer to the Project comparison analysis completed in Tables 3 through 5 of Exhibit B, Tab 7, Schedule 1.

c) Yes, as articulated in Exhibit B, Tab 7, Schedule 1, the selection of comparable line projects are reasonable as they are similar voltage, structure and conductor types; as well as involve the rebuild of existing 115 kV transmission infrastructure to a 230 kV double-circuit transmission line. Likewise, the comparable station projects are considered reasonable and were selected because of the similarities in scope of work.

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THE ROSS FIRM GROUP - 03

Reference:

PART III: Project Cost

3. Risk Identification and Contingency Budget

Reference #4: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application Lambton to Chatham Transmission Line Project, Exhibit B-7-1.

Interrogatory:

a) Please identify and describe any risks associated with the project, including:
   i. Technical risks
   ii. Environmental risks
   iii. Financial risks.

b) Is the proposed contingency budget appropriate and consistent with these identified risks?

Response:

a) Hydro One has not identified any material, unique technical risks that would relate to the construction of the Project. Once the Project is in-serviced, Hydro One expects the facilities to be integrated to the overall IESO-controlled grid and will be operated in accordance with uniform standards including the Transmission System Code.

   All potential adverse environmental effects of the Project have been addressed in the Class EA and are beyond the scope of this proceeding. Please refer to Procedural Order No. 1.

   Financial risks of the Project generally pertain to differences between forecast and actual costs incurred to construct the Project. Section 1.0 of Exhibit B, Tab 7, Schedule 1, provides information regarding the financial risks that predominantly contribute to the contingency amount that has been included in the Project estimated costs. There are other typical project risks that may materialize that are not predominantly contributing to the contingency, e.g., engagement and consultation risks, weather impacts, and commissioning risks. Please refer to Exhibit I, Tab 1, Schedule 4 for further information on the Project's contingency.

b) Yes, the proposed contingency is appropriate and consistent with these identified risks. As articulated in Exhibit B, Tab 7, Schedule 1, Hydro One follows an industry established best practices methodology in developing the contingency utilizing a risk management model that includes both a qualitative and a quantitative risk analysis of identified risks to the Project. Please refer to Exhibit I, Tab 1, Schedule 4 for further information on the Project's contingency.

THE ROSS FIRM GROUP - 04

Reference:

PART IV: Customer Impacts

4. Capital Contributions

Reference # 5: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit B-9-1.

Interrogatory:

a) Has Hydro One correctly determined the need for and the amount of any capital contributions required for the project? Please provide detailed calculations and justifications for any contributions identified.

Response:

a) There are no capital contributions required to deliver the Project as outlined in Exhibit B, Tab 9, Schedule 1.

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Reference:

PART IV: Customer Impacts

5. Transmission Rate Impacts

Reference # 6: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit B-9-1.

Interrogatory:

a) What are the projected transmission rate impacts resulting from the project?

b) Are these impacts reasonable given the needs the project satisfies and the benefits it provides?

Response:

a) As detailed in the Table of Exhibit B, Tab 9, Schedule 1, Section 3.0, the expected rate impact associated with the Project is a reduction of $0.14/month on a typical residential customer's bill under its approved Regulated Price Plan.

b) Yes, the resulting rate reduction is reasonable and flows to the benefit of all Ontario ratepayers. More specifically, the expected bill reduction is an outcome of the increased system benefits expected to arise from the operation of the Project. Notably, the new transmission line facilities will ensure sufficient bulk transfer capability east of Chatham to reliably supply the rapidly increasing load demand in the Windsor-Essex Region and surrounding Chatham area. The new transmission line will also improve the deliverability of resources in Lambton-Sarnia, as well as enable the west of Chatham reinforcements to operate to their full capability, maximizing the benefit of those assets.

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THE ROSS FIRM GROUP - 06

Reference:

PART V: Reliability and Quality of Electricity Service

6. Impact on Reliability

Reference # 7: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit F-1-1.

Interrogatory:

a) Has Hydro One established that the project will maintain or improve reliability? Please provide the final System Impact Assessment (SIA) and explain its findings regarding the project's impact on the reliability of the integrated power system.

Response:

a) The accountability for the System Impact Assessment, including the assessment of the Project's impact on the reliability of the integrated power system, rests with the IESO. To that end, the IESO has established that the Project will maintain or improve reliability as detailed in the Final SIA which is provided as Attachment 1 of this Schedule. Notably, the Final SIA has not substantively changed from the Draft SIA included in the prefiled evidence of this Application found at Exhibit F, Tab 1, Schedule 1, Attachment 1.

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System Impact Assessment Report

Final Report - Public

CAA ID: 2021-699
Project: Lambton TS – New 230 kV Circuits
Connection Applicant: Hydro One Networks Inc.

August 7, 2024

ieso
Connecting Today.
Powering Tomorrow.

Acknowledgement

The IESO wishes to acknowledge the assistance of Hydro One in completing this assessment.

Disclaimers

IESO

This report has been prepared solely for the purpose of assessing whether the connection applicant's proposed connection with the IESO-controlled grid would have an adverse impact on the reliability of the integrated power system and whether the IESO should issue a notice of conditional approval or disapproval of the proposed connection under Chapter 4, section 6 of the Market Rules.

Conditional approval of the project is based on information provided to the IESO by the connection applicant and Hydro One at the time the assessment was carried out. The IESO assumes no responsibility for the accuracy or completeness of such information, including the results of studies carried out by Hydro One at the request of the IESO. Furthermore, the conditional approval is subject to further consideration due to changes to this information, or to additional information that may become available after the conditional approval has been granted.

If the connection applicant has engaged a consultant to perform connection assessment studies, the connection applicant acknowledges that the IESO will be relying on such studies in conducting its assessment and that the IESO assumes no responsibility for the accuracy or completeness of such studies including, without limitation, any changes to IESO base case models made by the consultant. The IESO reserves the right to repeat any or all connection studies performed by the consultant if necessary to meet IESO requirements.

Conditional approval of the proposed connection means that there are no significant reliability issues or concerns that would prevent connection of the proposed project to the IESO-controlled grid. However, the conditional approval does not ensure that a project will meet all connection requirements. In addition, further issues or concerns may be identified by the transmitter(s) during the detailed design phase that may require changes to equipment characteristics and/or configuration to ensure compliance with physical or equipment limitations, or with the Transmission System Code, before connection can be made.

This report has not been prepared for any other purpose and should not be used or relied upon by any person for another purpose. This report has been prepared solely for use by the connection applicant and the IESO in accordance with Chapter 4, section 6 of the Market Rules. This report does not in any way constitute an endorsement of the proposed connection for the purposes of obtaining a contract with the IESO for the procurement of supply, generation, demand response, demand management or ancillary services.

The IESO assumes no responsibility to any third party for any use, which it makes of this report. Any liability which the IESO may have to the connection applicant in respect of this report is governed by Chapter 1, section 13 of the Market Rules. In the event that the IESO provides a draft of this report to the connection applicant, the connection applicant must be aware that the IESO may revise drafts of this report at any time in its sole discretion without notice to the connection applicant. Although the IESO will use its best efforts to advise you of any such changes, it is the responsibility of the connection applicant to ensure that the most recent version of this report is being used. The IESO provides no comment, representation or opinion, express or implied, with respect to who should bear the cost of IESO requirements for connection in this report and disclaims any liability in connection therewith.

Hydro One

The results reported in this report are based on the information available to Hydro One, at the time of the study, suitable for a System Impact Assessment of this connection proposal.

The short circuit and thermal loading levels have been computed based on the information available at the time of the study. These levels may be higher or lower if the connection information changes as a result of, but not limited to, subsequent design modifications or when more accurate test measurement data is available.

This study does not assess the short circuit or thermal loading impact of the proposed facilities on load and generation customers.

In this report, short circuit adequacy is assessed only for Hydro One circuit breakers. The short circuit results are only for the purpose of assessing the capabilities of existing Hydro One circuit breakers and identifying upgrades required to incorporate the proposed facilities. These results should not be used in the design and engineering of any new or existing facilities. The necessary data will be provided by Hydro One and discussed with any connection applicant upon request.

The ampacity ratings of Hydro One facilities are established based on assumptions used in Hydro One for power system planning studies. The actual ampacity ratings during operations may be determined in real-time and are based on actual system conditions, including ambient temperature, wind speed and facility loading, and may be higher or lower than those stated in this study.

The additional facilities or upgrades which are required to incorporate the proposed facilities have been identified to the extent permitted by a System Impact Assessment under the current IESO Connection Assessment and Approval process. Additional facility studies may be necessary to confirm constructability and the time required for construction. Further studies at more advanced stages of the project development may identify additional facilities that need to be provided or that require upgrading.

Table of Contents

Project Description

According to the *Need of Bulk System Reinforcements West of London* study report issued by the IESO in September 2021, Hydro One Networks Inc. (the "connection applicant" and "transmitter") is proposing to build two new 59 km long 230 kV circuits, L34C and L35C, between Lambton Transformer Station (TS) and Chatham Switching Station (SS) (the "project") to address the insufficient system capability in supplying the loads west of Chatham. The project will include:

- Disconnecting the existing 115 kV circuit N5K between Kent TS and Sarnia Scott TS supplying the load at Wallaceburg TS by Q1, 2026, and temporarily supplying this load from the 230 kV circuits L28C and L29C at 31.4 km from Chatham SS;
- Building two new 59 km long 230 kV circuits L34C and L35C between Lambton TS and Chatham SS with Wallaceburg TS permanently connecting to the two new 230 kV circuits at 31.4 km from Chatham SS;

  As a transition, the section of the new circuits between Wallaceburg TS and Chatham SS will be in-service in Q1, 2027 to supply the load radially at Wallaceburg TS. The remaining section between Wallaceburg TS and Lambton TS will be in-service in Q4, 2028;
- Installing two new 230 kV bus tie breakers at Chatham SS by Q4, 2028.

The new circuits will be on double-circuit towers. During the SIA process, the connection applicant advised that discussion was going on regarding the possible use of a four-circuit tower at one location where the new line crosses the existing L28C/L29C line. If used, the four circuits (the two new circuits, L28C and L29C) would be on a common tower. The connection applicant will provide a confirmation when a decision is made. This SIA assumed no use of a four-circuit tower.

Notification of Conditional Approval

This assessment concludes that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in this report are implemented. Therefore, the assessment supports the release of the Notification of Conditional Approval for connection of the project.

Assessment Findings

System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, and load security in accordance to the Ontario Resource and Transmission Adequacy Criteria (ORTAC) and in line with applicable reliability standards. Based on the assessment results, the following assessment findings were identified:

(1) During the transition period when Wallaceburg TS is connected to circuits L28C and L29C, or radially connected to Chatham SS, the load at Wallaceburg TS will exacerbate the pre-contingency thermal overloads on L28C and L29C, under L28C, L29C, W44LC, W45LS, or S47C outage conditions during the winter. The whole Brighton Beach CGS facility was assumed in-service under all outage conditions.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, remedial action scheme (RAS), upgrading of equipment and any project specific items not covered in the general requirements.

1. Hydro One shall install RAS facilities to include the project in the Lakeshore RAS and Lambton Generation Rejection (G/R) Scheme. During the IESO Market Registration process, a revised Facility Description Document (FDD) for Lakeshore RAS and Lambton G/R Scheme must be provided and finalized at least nine months prior to in-service. The FDD must contain the finalized RAS matrix as well as expected operating times. The actual operating times must be measured during commissioning and documented as a Performance Validation Record.

   If the FDD or performance testing as per the Performance Validation Record indicates a change in design or slower than expected operating times, as compared to what was assumed in this assessment, then further analysis of the project will need to be done by the IESO. This may delay the grant of IESO final approval to place the project in-service.

   Hydro One shall ensure that the RAS facilities comply with NPCC Reliability Reference Directory #7 as per the RAS type classification which will be finalized during the Market Registration process. To avoid any delay to the project, it is strongly recommended the RAS facilities be designed to meet NPCC Reliability Reference Directory #7 for NPCC Type I RAS before the RAS type classification is finalized. If deemed or expected to be a Type II or Limited Impact RAS, the transmitter shall ensure the RAS facilities have provisions to comply with NPCC Reliability Reference Directory #7 for Type I RAS in case the RAS is re-classified as NPCC Type I RAS in the future as the system evolves.

2. The connection applicant shall provide a confirmation to the IESO if a four-circuit tower is used for the new circuits and L28C/L29C. if yes, the IESO will assess the information and may need to amend this SIA report.

   The connection applicant is strongly recommended to not use a four-circuit tower for the new circuits and L28C/L29C as it will result in an outage condition to multiple circuits, compromising the real-time load supply reliability of the west of Chatham system.

3. To address Finding #1, for the transition period, Hydro One is required to revise their previous internal instruction for the west of Chatham system that addresses the principles of load interruption and restoration priority and supports coordination of outage planning and real time operation. The revised instruction shall take into account the load at Wallaceburg TS or the same amount of additional load west of Chatham.

General Requirements:

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code (TSC) and reliability standards. Some of the general requirements that are applicable to this project are presented in detail in Appendix A: General Requirements of this report.

Appendix A: General Requirements

The connection applicant shall satisfy all applicable requirements specified in the Market Rules, the Transmission System Code and reliability standards. This section highlights some of the general requirements that are applicable to the project.

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.

2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

   Note, the connection applicant may request an exception to the application of the BES definition. The procedure for submitting an application for exemption can be found in Market Manual 11.4: "Ontario Bulk Electric System (BES) Exception" at the IESO's website.

   The IESO's criteria for determining applicability of NERC reliability standards and NPCC Criteria can be found in the Market Manual 11.1: "Applicability Criteria for Compliance with NERC Reliability Standards and NPCC Criteria" at the IESO's website.

   Compliance with these reliability standards will be monitored and assessed as part of the IESO's Ontario Reliability Compliance Program. For more details about compliance with applicable reliability standards reliability standards, the connection applicant is encouraged to contact orcp@ieso.ca and also visit the Ontario Reliability Compliance Program webpage.

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves.

3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).

4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

   It is the connection applicant's responsibility to verify that all equipment and circuit breakers within the project are appropriately sized for the local fault levels.

   The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.

5. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

   Associated overvoltage protective relaying must be set to ensure that the project's equipment does not automatically trip for voltages up to 5% above the equipment's corresponding maximum continuous voltage as specified in section 4.2 of the ORTAC.

   BPS elements are deemed by the IESO to be essential to system reliability and security and must be protected by redundant protection systems in accordance with Section 8.2 of the TSC. These redundant protection systems must satisfy all requirements of the TSC, and in particular, they must be physically separated and not use common components, common battery banks, or common instrument transformer secondary windings.

   The protection systems for transmission voltage BES elements (whose rated voltage is higher than 100 kV) must be redundant. Redundancy must be present in protective relaying for normal fault clearing and control circuitry associated with protective functions including trip coils of the circuit breakers or other interrupting devices. These redundant protection systems must not use common instrument transformer secondary windings. A single communication system, if used, must be monitored and reported and a single DC supply, if used, must be monitored and reported for both low voltage and open circuit.

   As the electrical system evolves, transmission voltage non-BPS or non-BES elements (whose rated voltage is higher than 100 kV) within the project, may be re-classified as BPS elements or BES elements. The connection applicant is recommended to design the protection systems for these elements according to the protection requirements for BPS elements or have adequate provisions for future upgrade to meet those requirements.

6. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.

7. In accordance with Section 7.4 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.16 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.20 and Appendix 4.21, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

   The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.

8. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages. The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration

process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

At the sole discretion of the IESO, performance tests may be required at generation and transmission facilities. The objectives of these tests are to demonstrate that equipment performance meets the IESO requirements, and to confirm models and data are suitable for IESO purposes. The transmitter may also have its own testing requirements. The IESO and the transmitter will coordinate their tests, share measurements and cooperate on analysis to the extent possible.

Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca.

9. If the connection applicant is currently a participant in the Ontario Power System Restoration Plan, its restoration participant attachment is required to be updated to include the project according to Market Manual 7.8. For either an existing or newly identified participant in the Ontario Power System Restoration Plan, details regarding restoration participant requirements will be finalized during the IESO Market Registration process.

   If the project is classified as a Key Facility that is required to establish a Basic Minimum Power System following a system blackout, it shall meet testing requirements of Critical Components belonging to Key Facilities as specified in Market Manual 7.8. Key Facility, Basic Minimum Power System and Critical Component terms are defined in the NPCC Glossary of Terms.

10. The Ontario Resource and Transmission Assessment (ORTAC) states that the transmission system must be planned such that, following design criteria contingencies on the transmission system, affected loads can be restored with the restoration times listed below:
    a. All load must be restored within approximately a target of 8 hours;
    b. When the amount of load interrupted is greater than 150MW, the amount of load in excess of 150MW must be restored within approximately a target of 4 hours;
    c. When the amount of load interrupted is greater than 250MW, the amount of load in excess of 250MW must be restored within a target of 30 minutes.

11. As per Market Manual 1.4: Connection Assessment and Approval, the connection applicant will be required to provide a status report of its proposed project with respect to its progress upon request of the IESO using the project status report form on the IESO website. Failure to comply with project status requirements listed in Market Manual 1.4: Connection Assessment and Approval will result in the project being withdrawn.

    The connection applicant will be required to also provide updates and notifications in order for the IESO to determine if the project is "committed" as per Section 3.3 of Market Manual 1.4: Connection Assessment and Approval.

Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

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Reference:

PART V: Reliability and Quality of Electricity Service

7. Customer Impact Assessment (CIA)

Reference # 9: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit G-1-1.

Interrogatory:

a) Please provide the final Customer Impact Assessment (CIA). Does the final CIA conclude that the project will not have an adverse impact on customers with respect to reliability and quality of electricity service?

Response:

a) Yes, the Final CIA concludes that the Project will not have an adverse impact on customers with respect to reliability and quality of electricity service as detailed in Attachment 1 of this Schedule. Hydro One notes that the Final CIA has not substantively changed from the Draft CIA included in the prefiled evidence of this Application found at Exhibit G, Tab 1, Schedule 1, Attachment 1.

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483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

LAMBTON TS x CHATHAM SS NEW 2-CIRCUIT 230 kV LINE DEVELOPMENT

CIA ID: 2024-08

Revision: **Final**

Date: **August 16th , 2024**

Issued by: **Transmission System Planning Department**
Hydro One Networks Inc.

Prepared by:

Emeka Okongwu, P.Eng.
Senior Network Management Engineer
System Planning Division

Reviewed by:

Mark Brodie, P.Eng.
Manager - Transmission Planning
System Planning Division

DISCLAIMER

This Customer Impact Assessment was prepared based on information available about the connection of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project. It is intended to highlight significant impacts, if any, to affected transmission customers early in the project development process and thus allow an opportunity for these parties to bring forward any concerns that they may have including those needed for the review of the connection and for any possible application for "leave to construct". Subsequent changes **to the required modifications** or the implementation plan may affect the impacts of the proposed connection identified in Customer Impact Assessment. The results of this Customer Impact Assessment are also subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One Networks shall not be liable to any third party which uses the results of the Customer Impact Assessment and Addendums under any circumstances whatsoever, for any indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages, arises in contract, tort or otherwise.

Executive Summary

Hydro One Inc. proposes to develop the Lambton TS x Chatham SS New 2-circuit 230 kV Line project in the medium-term as the first phase in the reinforcement of the bulk transmission east of Chatham, and the second phase of reinforcement for the broader West of London region in order to reliably meet the requirements of the rapidly increasing load demand in the Windsor – Essex Region. This 63 km line project is planned for in service in Q4 2028.

Due to line routing considerations, the new line will repurpose about 41 km of the existing 115 kV line, N5K, which currently supplies Wallaceburg TS, a 2-25/33/42 MVA, 115/27.6 kV station, supplied from circuit N5K. Consequently, Wallaceburg TS will be converted to a 2-50/67/83 MVA, 230/27.6 kV station, and be supplied from the new line.

The project also involves the modification of the existing Lakeshore Remedial Action System (RAS), and Lambton Generation Rejection (G/R) scheme.

This Customer Impact Assessment (CIA) is concerned with the potential impact of the above project on transmission connected customers in the area.

An assessment of voltage performance and loading capability of the transmission facilities in the area has been carried out and documented in an IESO System Impact Assessment (**SIA**) Final Report, CAA ID 2021-699: Lambton x Chatham – New 230 kV Circuits, dated August 7th, 2024. The report indicates that with the application of the modified Lakeshore RAS and Lambton G/R scheme, as specified by the SIA, the thermal loading of the facilities would remain within their ratings, and that there are no voltage performance concerns at all connection points

The following potential impacts on existing customers in the area are reviewed is this CIA:

- Short circuit impact
- Impact on customer power supply reliability.

The findings of this CIA are as follows:

1. Following the incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project, the short circuit levels exceed the limits of the Transmission System Code (TSC) at Lambton 230 kV while remaining within the limits at all customer connection points. Lambton TS would have to be operated in a bus split mode to manage this exceedance. The largest percentage increase in symmetrical short circuit current due to this project is 135% at Wallaceburg TS 27.6 kV bus.

2. The incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project, specifically the conversion of Wallaceburg TS from 115 kV to 230 kV supply, will materially improve the power supply reliability for customers supplied from this station, substantially reduce the transmission line losses associated with supplying the station, and substantially increase the station supply capacity.

3. The Lakeshore RAS would affect only South Middle Road TS, Windsor NextStar TS and stations connected to the radial Lakeshore TS x Leamington TS circuits. Hence the reliability of supply to customers connected to other stations in the Windsor – Essex Region would not be affected.

1.0 INTRODUCTION

1.1 Background

Hydro One Inc. proposes to develop the Lambton TS x Chatham SS New double-circuit 230 kV Line project (Figure 1) in the medium-term in order to reliably meet the requirements of the rapidly increasing load demand in the Windsor – Essex Region. This would be the first phase in the reinforcement of the bulk transmission east of Chatham, and the second phase of reinforcement west of London, intended to eliminate transmission constraints which limit power transfers into the Windsor – Essex Region hence limiting load growth in the region. The rapid load growth in the region is driven by both the industrial and agricultural sectors. These transmission constraints are currently being managed with a Remedial Action System (RAS) which is located at Lakeshore TS. The RAS rejects load and generation, as required, to keep circuit flows within limits. This project is planned to be in service in Q4 2028.

Due to line routing considerations, the new line will repurpose a 41 km section of the existing Scott TS x Kent TS 115 kV single circuit line, N5K, which currently supplies Wallaceburg TS, a 115/27.6 kV load supply station. Consequently, this station would be disconnected from circuit N5K, converted to a 230/27.6 kV load supply station and connected to the two new circuits. Hence the station which is currently supplied by a single circuit would be supplied by two circuits thus increasing the supply reliability.

The existing Lakeshore Remedial Action System (RAS) and Lambton Generation Rejection (G/R) scheme are to be modified to reflect changes due to the transmission reinforcement brought about by this project.

In accordance with section 6 of the Ontario Energy Board's Transmission System Code, Hydro One Networks Inc (Hydro One) has carried out this Customer Impact Assessment (CIA) study to assess the impact of the proposed projects on existing customers in the affected area. The primary focus of this assessment is possible short circuit and reliability impact on transmission connected customers following the incorporation of the Lambton TS x Chatham SS new double-circuit 230 kV Line project. This study does not evaluate the overall impact of these projects on the bulk electricity system. The impact of the new facilities on the bulk electricity system is the subject of the System Impact Assessment (SIA) carried out by the Independent Electricity System Operator (IESO).

As part of the Connection Assessment and Approval (**CAA**) process, the IESO has carried out a System Impact Assessment (**SIA**) for the West of Chatham Transmission Development projects, and has documented the findings in the Final Report, CAA ID 2021-699: Lambton x Chatham – New 230 kV Circuits, dated August 7th 2024.

Transmission connected customers potentially impacted by the incorporation of this project were requested to provide comments to a draft report of this CIA study. The review period ended on June 7, 2024. All comments received on the draft report were addressed.

1.2 Customer List

The transmission customers in the area are;

- Trans Alta Energy Corporation (Sarnia)
- Imperial Oil (Sarnia Refinery Complex)
- Arlanxeo Canada Inc.
- St. Clair Power LP
- Shell Canada Products
- Nova Chemicals (Canada) Ltd
- Greenfield South Power Corporation
- Greenfield Energy Centre LP
- East Lake St. Clair Wind LP
- North Kent Wind 1 LP
- Brighton Beach Power LP
- Erieau Wind LP
- Kruger Energy Port Alma LP
- North Kent Wind 1 LP
- Romney Energy Centre LP
- South Kent Wind LP
- SP Belle River Wind LP
- Talbot Windfarm LP
- TerraForm IWG Ontario Holdings, LLC
- 2016 Comber Wind LP
- Hydro One Networks Inc
- Entegrus Powerlines Inc
- 2820853 Ontario Ltd.

Table 1 lists all stations and supply circuits of the existing transmission customers in the area.

Table 1: Transmission Customers in the Area

No.	Station	Connection	Connected Customer
1	Trans Alta Energy CGS	230 kV N6S, N7S	• Trans Alta Energy Corp (Sarnia)
2	Imperial Oil CTS	230 kV N6S, N7S	• Imperial Oil (Sarnia Refinery Complex)
3	Arlanxeo Canada Inc CTS	230 kV N6S, N7S	• Arlanxeo Canada Inc.
4	St Clair Energy Centre CGS	230 kV V41N, V43N	• St. Clair Power LP
5	Shell Sarnia CTS	230 kV L23N, V43N	• Shell Canada Products
6	Nova St Clair CTS	230 kV L23N, V43N	• Nova Chemicals (Canada) Ltd
7	Nova Corunna CTS	230 kV L27V, V41N	• Nova Chemicals (Canada) Ltd
8	Nova Moore CTS	230 kV L25V, L27V	• Nova Chemicals (Canada) Ltd
9	Greenfield Energy Centre CGS	230 kV L37G, L38G	• Greenfield Energy Centre LP
10	Leamington TS	230 kV H38, H39	• Hydro One Networks Inc.
11	Malden TS	230 kV H25J, H26J	• Essex Powerlines Corp. • Enwin Utilities Ltd • Hydro One Networks Inc.
12	Keith TS	230 kV H25J, H26J, J20B	• Brighton Beach Power LP • West Windsor Power
13	Lauzon TS	230 kV H53Z, H54Z	• Enwin Utilities Ltd. • Hydro One Networks Inc. • Essex Powerlines Corp.
14	Comber WFCGS	230 kV C42H, C43Z	• 2016 Comber Wind LP
15	Port Alma #1 WFCGS	230 kV C42H, C43H	• Kruger Energy Port Alma LP
16	Port Alma #2 WFCGS	230 kV C42H C43H	• Kruger Energy Port Alma LP
17	Dillon WFCGS	230 kV C42H	• TerraForm IWG Ontario Holdings, LLC
18	Belle River CGS	230 kV C42H	• SP Belle River Wind LP
19	Romney CGS	230 kV C64H	• Romney Energy Centre LP

20	South Kent Sattern CGS, Railbed CGS	230 kV C31	• South Kent Wind LP
21	East Lake St Clair CGS	230 kV L29C	• East Lake St Clair Wind LP
22	North Kent 1 CGS	230 kV L29C	• North Kent Wind 1 LP
23	GSPC CGS	230 kV L28C	• Greenfield South Power Corporation
24	Spence CGS	230 kV Spence SS	• Talbot Windfarm LP
25	Erieau WF CGS	230 kV S47C	• Erieau Wind LP
26	Kent TS	230 kV L28C, L29C	• Hydro One Networks Inc • Entegrus Powerlines Inc
27	Wallaceburg TS	230 kV L34C, L35C	• Hydro One Inc
28	Mastron CTS	230 kV H38	• 2820853 Ontario Ltd.
29	Windsor NextStar TS	230 kV H53Z, H54Z	• Hydro One Networks Inc.

2.0 Customer Impact Assessment Scope

The purpose of this CIA is to assess the potential impacts of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project on the existing transmission-connected load and generation customers in the general area. This is in accordance with the requirements of the Ontario Energy Board's Transmission System Code.

A review of the following potential impacts on existing customers is conducted in this CIA:

- Short circuit impact at the connection point
- Impact on customer power supply reliability

3.0 Load Flow

As documented in the SIA report, the results of load flow studies indicate thermal overload on L28C and L29C following recognized contingencies. The existing Lakeshore RAS and the existing Lambton G/R scheme will be modified to manage these overloads when contingencies occur. The SIA report did not indicate material voltage levels and voltage changes that violates Ontario Resource and Transmission Criteria (ORTAC) criteria for all 230 kV and 115 kV buses in the general area. The thermal overload of circuits is the consequence of the inadequacy of the existing transmission network facilities in the West system. The modified Lakeshore RAS and Lambton G/R scheme will be used to manage this inadequacy pending future transmission development.

Only South Middle Road TS, Windsor NextStar TS and stations connected to the Lakeshore TS x Leamington TS radial circuits will participate in the Lakeshore RAS load rejection.

4.0 Short-Circuit Study Analysis

Short-circuit studies were carried out to determine fault levels at customer connection points in the general area before, and after the incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project. These results would help customers determine if the proposed project results in short-circuit levels that are within the ratings of their existing equipment.

For the determination of fault levels, pre-fault voltages of 250 kV, 127 kV, 29 kV and 14.2 kV are assumed at 230 kV, 115 kV, 27.6 kV and 13.8 kV buses, respectively.

4.1 Prior to Incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project

Short-circuit studies were initially carried out to determine fault levels in the general area before the incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project in Q4 2028. The study results are summarized in Table 2, showing both symmetric and asymmetric fault currents.

As shown in Table 2, short circuit levels at all connection points are within the limits set out in Appendix 2 of the TSC. The applicable TSC limits for this project are summarized below for reference:

Nominal Voltage (kV)	Max 3-Phase Fault (kA)	Max SLG Fault (kA)
230	63	63
115	50	50
27.6 (4-wire)	17	12
13.8	21	10

4.2 With the Incorporation of Lambton TS x Chatham SS New 2-circuit 230 kV Line project

The results of short circuit studies following the incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project are shown in Table 3 along with the relative increase due to the project.

The results in Table 3 show that short circuit levels increase at all customers' connection points in the general area. These levels are still within the limits of the Transmission System Code, except for Lambton TS 230 kV bus where both the three-phase and single phase-to-ground limits are exceeded.

To manage this fault level exceedance, the Lambton 230 kV bus tie breakers would have to be operated open. The resulting fault levels in this mode of operation are within the limits of the code, as shown in Table 4. The largest percentage increase in symmetrical short circuit current due to this project is 135% at the Wallaceburg TS 27.6 kV bus due to its conversion from 115 kV supply to 230 kV supply.

All area customers are advised to review the short circuit results to ensure that their equipment ratings are adequate.

5.0 SUPPLY RELIABILITY AND CAPACITY

The IESO SIA report concluded that the Lambton TS x Chatham SS New 2-circuit 230 kV Line project does not have a material adverse impact on the reliability of the integrated power system, provided that the recommended modifications to the Lakeshore RAS and the Lambton G/R scheme are implemented.

The addition of the new 2-circuit Lambton TS x Chatham SS line will reinforce the bulk transmission system east of Chatham, allowing for increased power transfer into the Windsor -

Essex Region to reliably supply the forecast load growth in the region. This addition will improve the power supply reliability for customers in the region.

The conversion of Wallaceburg TS from a single circuit 115 kV supply to double-circuit 230 kV supply will improve supply reliability for customers supplied from this station, as the loss of the station would require a fault on two circuits which is a lower probability event than a fault on a single circuit. For this delivery point, the frequency of supply interruptions, due to both planned and forced outages, would be reduced from 1.46 interruptions/year to 0.06 interruptions/year, and the annual interruption duration would be reduced from 9.4565 minutes to 8.3500 minutes (Table 5).

This conversion combined with the use of significantly lower resistance conductor, relative to the existing N5K conductor, would significantly reduce the transmission line losses in supplying the station load. As per Table 6, the transmission line losses associated with this delivery point would be reduced from 2191 MWhr/year to 52 MWhr/year.

The two transformers at Wallaceburg TS which are currently rated at 25/33/42 MVA, 115/27.6 kV, would be replaced with larger size units (2-50/67/83 MVA, 230/27.6 kV). Hence the station supply capacity would increase from 63 MVA to 95 MVA, and then to 114 MVA if additional LV station work is completed. The increase in capacity would enable the station to provide supply to more customers.

6.0 CONCLUSIONS AND RECOMMENDATIONS

This CIA report presents results of incorporating the Lambton TS x Chatham SS new 2-circuit 230 kV Line project which is planned to be completed in Q4 2028. In particular, the results of short circuit analyses have been presented, including the beneficial impact of converting Wallaceburg TS from 115 kV supply to 230 kV supply.

The assessment as reported in the SIA document shows that voltage performance and circuit loading are within applicable criteria with the application of load and generation rejection as recommended in the report.

Short-circuit studies were carried out to determine the expected fault levels at customer transmission connection points following the incorporation of the Lambton TS x Chatham SS New 2-circuit 230 kV Line project. The Lambton 230 kV bus would have to be operated in split mode to manage the high short circuit levels resulting from this project. In this mode of operation the short circuit levels observed at all connection points, though substantially increased at some locations, are within the limits of the Transmission System Code.

It is recommended that area customers review the impact of the short-circuit changes on their facilities and take appropriate and timely action to address any safety/technical issues arising out of the changes which would result following the incorporation the Lambton TS x Chatham SS New 2-circuit 230 kV Line project in Q4 2028.

Figure 1: Map of Lambton – Chatham Area: With New 230 kV Line

Table 2: Fault Levels (kA) Before the Lambton TS x Chatham SS 2-cct 230 kV Line Project

Location	3-Phase		L-G	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical
Chatham SS 230 kV	27.43	30.79	25.17	28.06
Lambton P1K1 230 kV	60.52	77.72	61.15	78.29
Lambton P2K2 230 kV	60.52	84.20	61.15	84.93
Scott 230 kV	43.49	53.82	42.46	52.54
Keith 230 kV	21.86	28.34	24.04	32.78
Lauzon A 230 kV	10.76	12.44	10.40	12.44
Lauzon H 230 kV	10.71	12.32	10.36	12.33
Greenfield L37 230 kV	41.07	52.87	41.10	52.20
Greenfield L38 230 kV	40.08	49.19	38.88	46.85
TransAlta Energy 230 kV	34.99	43.08	30.83	40.16
Imperial Oil N6S 230 kV	34.81	40.47	31.91	35.86
Imperial Oil N7S 230 kV	34.56	40.15	31.58	35.41
Arlanxeo N6S 230 kV	36.13	42.11	33.40	37.74
Arlanxeo N7S 230 kV	36.48	42.57	33.87	38.39
St Clair EC V41N 230 kV	35.47	43.12	36.65	46.17
St Clair EC V43N 230 kV	35.57	43.28	36.72	46.28
N Chem SS V41N 230 kV	31.57	37.15	28.51	31.35
N Chem SS V43N 230 kV	31.73	37.37	28.53	31.39
Shell Sarnia L23N 230 kV	29.03	33.21	25.74	27.56
Shell Sarnia V23N 230 kV	29.99	34.57	27.33	30.09
Nova St Clair L23N 230 kV	30.78	35.75	27.75	29.92
Nova St Clair V43N 230 kV	31.52	36.79	29.17	32.48
Nova Corunna L27N 230 kV	27.69	31.43	24.06	26.04
Nova Corunna V41N 230 kV	27.41	31.07	23.85	25.79
Nova Moore L25V 230 kV	30.84	35.74	27.02	29.31
Nova Moore L27V 230 kV	30.91	35.81	27.01	29.31
GSPC Jct L28C 230 kV	37.09	42.91	35.41	41.06
HRPP JCT 230 kV	36.70	41.93	34.56	40.04
East LK St Clair 230 kV	15.76	17.51	13.88	15.15
North Kent Jct 230 kV	17.36	19.13	15.15	16.12
Kent TS L28C 230 kV	17.96	19.70	14.80	15.68
Kent TS L29C 230 kV	18.15	19.97	15.08	15.99
C31 SKWP CMS Jct 230 kV	17.56	19.22	15.54	16.99
Erieau WF Jct 230 kV	27.06	30.34	24.77	27.58
Spence CSS 230 kV	13.91	15.40	11.23	12.27
Kepa WF Jct C42H 230 kV	13.58	14.82	11.69	12.27
Kepa WF Jct C43H 230 kV	14.12	15.35	13.50	14.41
Railbed CGS 230 kV	8.21	8.93	7.32	8.45
Sattern CGS 230 kV	13.35	14.50	11.64	13.22
Comber Jct C42H 230 kV	19.63	21.87	19.40	22.35
Comber Jct C43H 230 kV	19.67	21.67	19.55	22.27
NOVA SS V41N 230 kV	31.57	37.15	28.51	31.35
Romney Jct 230 kV	15.11	16.47	13.69	14.78
Belle River Jct 230 kV	19.78	22.07	18.81	20.85
Brighton Beach J20B 230 kV	21.63	28.02	23.76	32.03
Windsor NextStar H53Z 230 kV	10.76	12.44	10.40	12.44
Windsor NextStar H54Z 230 kV	10.71	12.32	10.36	12.33
Mastron2 Jct 2230 kV	17.09	19.02	15.05	16.35
S Middle Rd H75 230 kV	22.44	25.16	21.52	24.16
S Middle Rd H76 230 kV	22.84	25.63	21.86	24.62
Leamington H38 230 kV	12.38	13.81	10.15	10.86
Leamington H39 230 kV	12.26	13.68	10.05	10.75
Lambton J 27.6 kV	9.15	12.53	6.53	8.80
Lambton Q 27.6 kV	10.61	14.22	8.18	10.72
Kent B 27.6 kV	13.26	17.29	10.49	13.80
Kent Y 27.6 kV	14.31	18.55	10.65	14.03
Kent EZ 27.6 kV	13.65	17.97	10.72	14.87
Wallaceburg 27.6 kV	7.13	7.13	7.28	7.28
Wallaceburg 230 kV	-	-	-	-
KEITH TS Y 27.600	12.57	16.68	9.54	12.75
KEITH TS B 27.600	13.31	17.69	10.05	13.40
LAUZON TS BQ27.600	15.13	20.65	11.28	16.20
LAUZON TS E 27.600	12.19	15.23	9.41	12.13
LAUZON TS J 27.600	12.4	15.30	9.42	12.24

Table 3: Fault Levels (kA) with the Lambton TS x Chatham SS 2-cct 230 kV Line Project - Lambton 230 kV bus Closed

Location	3-Phase		L-G		Increase (%)	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical	3-Ph Sym.	L-G Sym.
Chatham SS 230 kV	33.38	37.37	30.28	33.50	21.68	20.28
Lambton P1K1 230 kV	63.39	81.11	64.13	81.64	4.73	4.86
Lambton P2K2 230 kV	63.39	87.95	64.13	88.69	4.73	4.86
Scott 230 kV	43.99	54.32	42.77	52.86	1.15	0.72
Keith 230 kV	22.34	28.87	24.42	33.22	2.20	1.61
Lauzon A 230 kV	11.03	12.71	10.57	12.60	2.44	1.59
Lauzon H 230 kV	10.97	12.58	10.52	12.50	2.45	1.59
Greenfield L37 230 kV	42.23	54.20	42.01	53.18	2.82	2.21
Greenfield L38 230 kV	41.22	50.40	39.75	47.72	2.84	2.23
TransAlta Energy 230 kV	35.29	43.37	30.98	40.31	0.84	0.48
Imperial Oil N6S 230 kV	35.11	40.77	32.08	36.02	0.88	0.52
Imperial Oil N7S 230 kV	34.86	40.44	31.74	35.56	0.87	0.51
Arlanxeo N6S 230 kV	36.47	42.44	33.59	37.91	0.92	0.55
Arlanxeo N7S 230 kV	36.82	42.90	34.06	38.57	0.93	0.56
St Clair EC V41N 230 kV	35.86	43.52	36.93	46.47	1.09	0.78
St Clair EC V43N 230 kV	35.96	43.67	37.00	46.58	1.10	0.78
N Chem SS V41N 230 kV	32.00	37.58	28.79	31.62	1.37	0.97
N Chem SS V43N 230 kV	32.17	37.81	28.80	31.65	1.37	0.95
Shell Sarnia L23N 230 kV	29.36	33.53	25.94	27.74	1.12	0.74
Shell Sarnia V23N 230 kV	30.32	34.90	27.53	30.28	1.10	0.73
Nova St Clair L23N 230 kV	31.14	36.12	27.97	30.13	1.19	0.80
Nova St Clair V43N 230 kV	31.88	37.15	29.40	32.70	1.16	0.78
Nova Corunna L27N 230 kV	28.02	31.76	24.26	26.23	1.20	0.80
Nova Corunna V41N 230 kV	27.73	31.39	24.04	25.97	1.19	0.81
Nova Moore L25V 230 kV	31.32	36.22	27.32	29.61	1.54	1.12
Nova Moore L27V 230 kV	31.38	36.28	27.30	29.60	1.53	1.08
GSPC Jct L28C 230 kV	37.59	43.40	35.82	41.46	1.35	1.16
HRPP JCT 230 kV	37.20	42.43	34.98	40.45	1.38	1.20
East LK St Clair 230 kV	16.10	17.87	14.10	15.37	2.13	1.61
North Kent Jct 230 kV	18.28	20.10	15.79	16.76	5.31	4.23
Kent TS L28C 230 kV	19.79	21.64	16.02	16.91	10.15	8.25
Kent TS L29C 230 kV	19.99	21.93	16.32	17.23	10.14	8.22
C31 SKWP CMS Jct 230 kV	19.71	21.42	17.04	18.50	12.21	9.65
Erieau WF Jct 230 kV	32.78	36.65	29.65	32.76	21.15	19.69
Spence CSS 230 kV	14.62	16.15	11.62	12.67	5.09	3.51
Kepa WF Jct C42H 230 kV	14.53	15.78	12.23	12.80	6.97	4.66
Kepa WF Jct C43H 230 kV	15.10	16.34	14.18	15.07	6.98	5.01
Railbed CGS 230 kV	8.62	9.34	7.57	8.70	4.98	3.46
Sattern CGS 230 kV	14.52	15.69	12.40	13.99	8.81	6.51
Comber Jct C42H 230 kV	21.18	23.46	20.47	23.45	7.91	5.51
Comber Jct C43H 230 kV	21.22	23.22	20.63	23.35	7.86	5.49
NOVA SS V41N 230 kV	32.00	37.58	28.79	31.62	1.37	0.97
Romney Jct 230 kV	16.12	17.49	14.29	15.38	6.67	4.43
Belle River Jct 230 kV	21.19	23.51	19.71	21.75	7.14	4.78
Brighton Beach J20B 230 kV	22.10	28.54	24.13	32.46	2.16	1.58
Windsor NextStar H53Z 230 kV	11.03	12.71	10.57	12.60	2.44	1.58
Windsor NextStar H54Z 230 kV	10.97	12.58	10.52	12.50	2.45	1.58
Mastron2 Jct 2230 kV	18.19	20.14	15.65	16.94	6.44	4.03
S Middle Rd H75 230 kV	24.39	27.16	22.79	25.44	8.70	5.94
S Middle Rd H76 230 kV	24.86	27.71	23.18	25.95	8.87	6.04
Leamington H38 230 kV	12.94	14.38	10.41	11.12	4.52	2.62
Leamington H39 230 kV	12.81	14.24	10.31	11.01	4.47	2.61
Lambton J 27.6 kV	9.16	12.54	6.54	8.80	0.10	0.05
Lambton Q 27.6 kV	10.62	14.23	8.19	10.73	0.08	0.04
Kent B 27.6 kV	13.38	17.51	10.54	13.89	0.91	0.48
Kent Y 27.6 kV	14.43	18.77	10.69	14.12	0.86	0.42
Kent EZ 27.6 kV	13.76	18.14	10.76	14.95	0.77	0.40
Wallaceburg 27.6 kV	16.79	21.47	11.95	15.72	135.40	64.14
Wallaceburg 230 kV	15.97	17.33	11.94	12.46	-	-
KEITH TS Y 27.600	12.59	16.70	9.55	12.76	0.2	0.1
KEITH TS B 27.600	13.33	17.71	10.06	13.41	0.2	0.1
LAUZON TS BQ27.600	15.20	20.73	11.31	16.23	0.5	0.3
LAUZON TS E 27.600	12.23	15.28	9.43	12.15	0.3	0.2
LAUZON TS J 27.600	12.08	15.34	9.43	12.26	-2.6	0.1

Table 4: Fault Levels (kA) with the Lambton TS x Chatham SS 2-cct 230 kV Line Project - Lambton 230 kV bus tie breakers Open

Location	3-Phase (kA)		L-G (kA)		Increase (%)	
	Symmetrical	Asymmetrical	Symmetrical	Asymmetrical	3-Ph Sym.	L-G Sym.
Chatham SS 230 kV	33.35	37.34	30.26	30.01	21.60	20.23
Lambton P1K1 230 kV	43.23	54.99	42.04	34.38	-28.58	-31.25
Lambton P2K2 230 kV	38.13	52.71	38.66	22.42	-37.00	-36.78
Scott 230 kV	43.55	53.84	42.46	15.02	0.13	0.01
Keith 230 kV	22.34	28.87	24.42	12.65	2.19	1.60
Lauzon A 230 kV	11.03	12.71	10.57	14.88	2.43	1.58
Lauzon H 230 kV	10.97	12.58	10.52	21.69	2.44	1.58
Greenfield L37 230 kV	33.05	43.00	33.31	21.73	-19.54	-18.97
Greenfield L38 230 kV	29.47	36.82	28.79	29.89	-26.47	-25.95
TransAlta Energy 230 kV	35.03	43.10	30.84	13.90	0.09	0.02
Imperial Oil N6S 230 kV	34.84	40.50	31.92	34.00	0.10	0.01
Imperial Oil N7S 230 kV	34.59	40.18	31.58	13.11	0.10	0.01
Arlanxeo N6S 230 kV	36.17	42.14	33.41	29.49	0.10	0.01
Arlanxeo N7S 230 kV	36.52	42.60	33.88	42.93	0.10	0.01
St Clair EC V41N 230 kV	35.04	42.64	36.28	16.91	-1.19	-1.02
St Clair EC V43N 230 kV	35.95	43.65	36.98	16.12	1.06	0.70
N Chem SS V41N 230 kV	30.19	35.65	27.43	28.66	-4.37	-3.80
N Chem SS V43N 230 kV	31.12	36.66	27.97	46.75	-1.94	-1.96
Shell Sarnia L23N 230 kV	28.35	32.48	25.24	44.18	-2.36	-1.95
Shell Sarnia V23N 230 kV	30.06	34.62	27.31	23.09	0.24	-0.07
Nova St Clair L23N 230 kV	30.01	34.92	27.16	23.22	-2.50	-2.11
Nova St Clair V43N 230 kV	31.59	36.84	29.15	5.47	0.25	-0.07
Nova Corunna L27N 230 kV	27.23	30.94	23.67	8.03	-1.66	-1.63
Nova Corunna V41N 230 kV	26.38	30.00	23.09	32.36	-3.76	-3.16
Nova Moore L25V 230 kV	28.85	33.60	25.48	44.74	-6.46	-5.71
Nova Moore L27V 230 kV	29.34	34.10	25.80	23.54	-5.06	-4.48
GSPC Jct L28C 230 kV	28.57	33.91	28.39	23.23	-22.96	-19.83
HRPP JCT 230 kV	30.53	35.42	29.07	28.61	-16.82	-15.89
East LK St Clair 230 kV	15.88	17.65	13.96	28.35	0.78	0.57
North Kent Jct 230 kV	18.21	20.03	15.74	23.37	4.88	3.90
Kent TS L28C 230 kV	19.74	21.59	15.99	23.38	9.87	8.06
Kent TS L29C 230 kV	19.99	21.93	16.32	27.44	10.13	8.21
C31 SKWP CMS Jct 230 kV	19.70	21.42	17.04	27.60	12.17	9.62
Erieau WF Jct 230 kV	32.76	36.63	29.64	31.59	21.08	19.63
Spence CSS 230 kV	14.62	16.14	11.62	31.61	5.08	3.50
Kepa WF Jct C42H 230 kV	14.52	15.78	12.23	25.27	6.95	4.65
Kepa WF Jct C43H 230 kV	15.10	16.34	14.17	25.32	6.96	4.99
Railbed CGS 230 kV	8.62	9.33	7.57	14.41	4.97	3.44
Sattern CGS 230 kV	14.52	15.69	12.39	14.16	8.78	6.50
Comber Jct C42H 230 kV	21.17	23.45	20.46	15.83	7.88	5.49
Comber Jct C43H 230 kV	21.21	23.22	20.62	13.19	7.83	5.47
NOVA SS V41N 230 kV	30.19	35.65	27.43	13.17	-4.37	-3.80
Romney Jct 230 kV	16.12	17.49	14.29	15.30	6.65	4.41
Belle River Jct 230 kV	21.19	23.50	19.71	15.48	7.12	4.77
Brighton Beach J20B 230 kV	22.10	28.54	24.13	15.53	2.15	1.57
Windsor NextStar H53Z 230 kV	11.03	12.70	10.57	15.42	2.43	1.58
Windsor NextStar H54Z 230 kV	10.97	12.58	10.52	13.87	2.44	1.58
Mastron2 Jct 2230 kV	18.19	20.13	15.65	12.77	6.41	4.01
S Middle Rd H75 230 kV	24.38	27.15	22.79	12.30	8.67	5.92
S Middle Rd H76 230 kV	24.86	27.70	23.18	11.55	8.84	6.02
Leamington H38 230 kV	12.93	14.38	10.41	10.39	4.51	2.62
Leamington H39 230 kV	12.81	14.24	10.31	9.87	4.45	2.60
Lambton J 27.6 kV	9.08	12.41	7.83	9.72	-0.79	-0.38
Lambton Q 27.6 kV	10.54	14.10	0.80	0.80	-0.69	-0.35
Kent B 27.6 kV	13.38	17.51	3.19	3.44	0.90	0.48
Kent Y 27.6 kV	14.43	18.77	2.94	3.18	0.85	0.42
Kent EZ 27.6 kV	13.76	18.13	7.94	10.46	0.77	0.40
Wallaceburg 27.6 kV	16.79	21.47	9.74	11.77	135.38	64.14
Wallaceburg 230 kV	15.51	16.88	10.34	12.34	-	-
KEITH TS Y 27.6 kV	12.59	16.70	9.55	12.76	-	-
KEITH TS B 27.6 kV	13.33	17.71	10.06	13.41	-	-
LAUZON TS BQ27. 6 kV	15.20	20.73	11.31	16.23	-	-
LAUZON TS E 27.6 kV	12.23	15.28	9.43	12.15	-	-
LAUZON TS J 27.6 kV	12.08	15.34	9.43	12.26	-	-

Table 5: Reliability Impact of Wallaceburg TS 230 kV Conversion

Performance Measure	**Frequency of supply interruptions/year**	**Duration of interruptions/year (min)**
Wallaceburg TS: 115 kV supply	1.4565	9.4565
Wallaceburg TS: 230 kV supply	0.0627	8.3500

Table 6: Supply Line Loss Impact of Wallaceburg TS 230 kV Conversion

	Supply line losses/year (MWhr)
Wallaceburg TS: 115 kV supply	2191
Wallaceburg TS: 230 kV supply	52

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Reference:

PART VI: Route Map and Form of Landowner Agreements

8. Scope of Easement Language

Reference #10: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit E-1-1 – Form of Transfer and Grant of Easement.

Interrogatory:

a) The Ross Firm Group has previously raised concerns regarding the broad scope of the easement language proposed by Hydro One. Please clarify the specific rights Hydro One intends to exercise under this easement, particularly regarding:
   i. Access rights for maintenance, repair, and emergency purposes
   ii. Restrictions on landowners' use of the land within the easement area
   iii. Provisions for compensation for any business or property loss resulting from Hydro One's use of the easement.

b) Under the current Application for Leave to Construct, the scope of easement language would reasonably be limited to those steps required to enter upon, prepare, construct and maintain the new project during its serviceable life. However, the grant language proposed by HONI includes: "add to, enlarge, alter… move, remove, replace, reinstall, reconstruct, relocate, supplement…". Is this scope of grant necessary or appropriate for the project approval being applied for?

c) Further to b. above, is it the Applicant's position that should further works on the easement lands, unrelated to the current project, or for which subsequent regulatory approval would be required, be undertaken, all necessary compensation and consultation has been satisfied by the grant of easement and compensation paid under the current Application?

d) Further to b. above, the grant provides for the addition of 'telecommunications systems…" which not only supports the proposed project, but expands to "a related business venture".
   i. Please provide details of related business ventures.
   ii. Please provide details of the economic models for those related business ventures, including revenue potential, operational costs, types of related business ventures.

iii. Please provide details of the authority the OEB has to grant approval for this additional and apparently unrelated component of the construction contemplated by the Applicant.

iv. Please provide details of the compensation landowners will receive from these related business ventures, as leave to construct sought and the consequent authority to expropriate relates to the proposed project that is the subject of this Application and not peripheral revenue generating activities contemplated by the Applicant.

e) Are there any circumstances under which Hydro One would agree to limit or condition its easement rights?

Response:

a)

i. Hydro One intends to rely on the rights granted within Section 1 of the Transfer and Grant of Easement included in this Application to access the easement lands for the safe operation and maintenance of the transmission line. Additionally, in emergency scenarios, Hydro One will utilize the easement rights to conduct emergency repairs as required but may also rely on legislative permissions to access the transmission infrastructure in emergency scenarios.

ii. Landowners' must keep the easement corridor clear of all buildings, structures, erections, installations, or other obstructions of any nature whether above or below ground, including removal of any materials and equipment or plants and natural growth, which may endanger the safe operation of the transmission line. Restrictions on the easement lands are specified within Section 2 of the Transfer and Grant of Easement included in this Application.

iii. As outlined in Section 1 (f) of the Transfer and Grant of Easement included in this Application, all activities that HONI completes within the easement corridor is subject to compensation to the landowner for any crop or physical damage sustained including agri-business.

b) The Transfer and Grant of easement language included in this Application is consistent with language included in previous Leave to Construct applications, previously approved by the OEB. Additionally, this language is Hydro One's standard transmission line easement language utilized across the Province. The specific language noted, provides Hydro One flexibility with its operation and upkeep of its transmission line assets, including those which may be required in the future. Voluntarily acquiring easement rights using incentive-based market valuations principles is intended to provide fair compensation to the affected landowner and provides Hydro One with the flexibility to continue to operate and maintain transmission grid facilities and in a manner that benefits all customers who are provided safe and reliable transmission service from these facilities.

c) Generally, yes. If a future project could be constructed within an existing easement, and without the need for additional easement rights (as prescribed in the terms of the existing easement) and no temporary working rights were required in order to construct and operate the future project, then Hydro One would not reasonably expect to provide additional compensation to the original grantor, or its successors. If the future project required regulatory approvals, such as those found under s.92 of the OEB Act, but Hydro One held all necessary easement rights to construct and operate at least that portion of the future project across its existing easements, Hydro One would not include as part of the forecast future project costs additional compensation for the benefit of the original grantor or its successors. That said, it is possible that a new and substantive future project wholly situated within an existing easement could potentially result in incremental injurious affection to the remainder lands rights held by the grantor. The assessment of this type of damage, or any others, would be considered based on the then prevailing facts and circumstances, including, compliance with all legislative requirements at that time. Hydro One has not experienced alterations made to existing transmission facilities wholly situated within an existing easement as giving rise to incremental damages such as incremental injurious affection. Again, the prevailing facts and circumstances and legislative requirements arising with such alterations would be considered at that time.

d)

i. The reference to “telecommunication systems” and “related business venture” within Hydro One’s Transfer and Grant of Easement reflect the rights provided to Hydro One within Section 42 of the Electricity Act. These rights include the right to utilize transmission and distribution infrastructure for the purpose of providing telecommunication services and enter into agreements with others, authorizing them to attach wires or other telecommunication facilities to this infrastructure for the purposes of supplying telecommunication systems. Additionally, telecommunication systems form part of the transmission line infrastructure that is critical for the safe, secure and reliable operation of a transmission line (i.e., grid protection and safe control).

ii. No economic modelling has been completed, as there are no related business ventures contemplated at this time.

iii. Please refer to response in part d i) above. The language found in the Transfer and Grant of Easement is consistent with the rights prescribed in Section 42 of the *Electricity Act*.

iv. Under Section 42 of the *Electricity Act*, an electric transmitter, in this case Hydro One, would not be required to pay any compensation for attaching wires or other telecommunication facilities to a transmission line. Attaching additional wires or other telecommunication facilities to existing structures is not reasonably expected to negatively impact the use and enjoyment of a landowner's remaining property rights.

e) As noted in response to part b) above, the form of easement agreement included in this Application is consistent with those that have been approved by the OEB and used across the Province by Hydro One. Hydro One is unaware of any unique circumstances or features associated with this Project that would justify imposing additional limits or conditions in the form of the easement agreement. Maintaining a practice of uniform and consistent easement agreements promotes administrative efficiencies. Achieving greater operational efficiencies is consistent with the policy objectives of incentive-based rate-making established by the OEB and ultimately provides benefits to Hydro One's customers.

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Reference:

PART VI: Route Map and Form of Landowner Agreements

9. Impact on Agricultural Operations

Reference # 11: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit E-2-1.

Interrogatory:

a) Given that some of the affected properties are used for agricultural purposes, how does Hydro One intend to mitigate potential disruptions to farming activities during both the construction and operational phases of the project?

b) What post construction provisions will be made for compensating landowners for any loss of crop production, additional operational costs, or other agricultural impacts caused by the project?

c) What decommissioning plans (e.g. removal of HONI infrastructure) exist for the point in time the project or facilities are no longer necessary.

d) What is the budget attributed to decommissioning the project?

Response:

a) During the construction phase of the Project, all property owners who have active arable agricultural lands impacted by the corridor, will be compensated for their crop lands out of production. Hydro One and its contractor will use all reasonable efforts to work with property owners so that they may carry out agricultural operations on lands situated outside of the construction corridor. For example, access road crossovers will be implemented in consultation with individual property owners so that agricultural operations may continue across and adjacent to the construction corridor during Project construction. If circumstances arise that prevent ongoing agricultural operations, Hydro One and its contractor will ensure affected property owners are compensated for crop lands that could not be produced or harvested due to the Project construction activities. Additionally Hydro One and its contractor will consult with individual property owners to ensure impacts to their agricultural operations are limited where possible.

During the operational phase of the Project, Hydro One will consult with property owners when access and activities will take place on agricultural lands for the operation and maintenance of the transmission line. Hydro One will use reasonable efforts to accommodate property owner access timing requests and limit impacts to agricultural operations, where possible.

b) During the post-construction phase of the Project, Hydro One will compensate three years of post-construction crop lands out of production for the corridor lands in recognition of potential soil compaction caused by the construction activities of the Project. Landowners will be able to continue agricultural activities within the corridor post-construction. Hydro One recognizes there may be unique or exceptional circumstances that may exist that require further compensation for lands out of production. These unique and exceptional circumstances will be identified and determined in consultation with the impacted landowner and appropriate compensation will be advanced where reasonable.

c) There are currently no decommissioning plans for these new facilities; the need for the Project does not envision any need to decommission these facilities in the foreseeable future.

d) Please refer to response in part c) above.

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Reference:

PART VII: Environmental and Community Impact
10. Environmental Assessment and Mitigation Measures

Reference #12: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Environmental Study Report (ESR), Exhibit F-1-1.

Interrogatory:

a) Hydro One has completed an Environmental Assessment (EA) for the project. Please provide an overview of the key findings of the EA and how Hydro One plans to address any identified environmental concerns.

b) What specific mitigation measures will Hydro One implement to minimize the environmental impact during the construction and operational phases?

Response:

a) The Final Environmental Study Report ("ESR") was filed on February 5, 2024, with the Ministry of Environment, Conservation and Parks, in accordance with Class EA process approved under the Ontario *Environmental Assessment Act*[1]*.* The key findings and mitigation measures Hydro One intends to implement are described in that report and are not matters relevant to this proceeding unless they are demonstrated to be issues that concern electricity price, reliability and quality of electricity service. Please refer to the OEB's findings as described in Procedural Order No. 1.

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

[1] https://www.ontario.ca/laws/statute/90e18

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Reference:
PART VII: Environmental and Community Impact
11. Community and Stakeholder Engagement

Reference #13: EB-2024-0155 – Hydro One Networks Inc. Leave to Construct Application – Lambton to Chatham Transmission Line Project, Exhibit G-2-1.

Interrogatory:
a) What ongoing engagement and communication strategies will Hydro One employ to keep stakeholders informed and address their concerns as the project progresses?

Response:
a) Hydro One is committed to maintaining transparent and continuous communication with all stakeholders throughout the duration of the Project. Hydro One's approach includes several key strategies to ensure that stakeholders are well-informed, and their concerns are adequately addressed as the Project progresses:
- Pre-Construction Open House: Hydro One will host a pre-construction open house to provide detailed information on the Project's technical aspects, construction planning, and what community members and impacted property owners can expect during the course of the Project.
- Advanced Notifications: Hydro One's goal is to ensure that there is a clear understanding of any concerns before the execution phase, with Hydro One real estate representatives working closely with property owners to obtain voluntary agreements and resolve any issues prior to the start of construction.
- Dedicated Construction Point Person: Throughout the Project, property owners will have direct access to a dedicated construction point person, who will be available to address any questions or concerns that arise as the work progresses. This ensures that property owners have a clear and direct line of communication with the construction team.
- Community-Wide Notifications: The broader community will be kept informed about project milestones through a variety of channels, including notices, radio and newspaper advertisements, and email blasts.
- Project Website: A dedicated project website will be regularly updated to reflect the latest developments, providing stakeholders with up-to-date project information at all times.
- Community Relations Support: Hydro One will have a dedicated community relations representative available to address any questions or concerns from property owners or community members as the project progresses. This

representative will ensure that any work affecting the community is communicated effectively through the appropriate channels, including direct communications and updates.

By employing these engagement and communication strategies, Hydro One aims to foster an ongoing dialogue with stakeholders, ensuring that their concerns are addressed promptly and that they remain informed throughout the Project.

VECTOR PIPELINE INC. - 01

Reference:
Hydro One Networks Application, Exhibit F-1-1, Page 6

> System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, and load security in accordance to the Ontario Resource and Transmission Adequacy Criteria (ORTAC) and in line with applicable reliability standards.

Interrogatory:

a) Please confirm that if the AC Mitigation study recommends additional mitigation installed on Vector Pipeline assets, costs associated with the installation of this mitigation will be paid by Hydro One.

Response:

a) Confirmed. If any additional mitigation is required, the associated costs will be paid by Hydro One.

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