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BY EMAIL AND RESS

August 20, 2026

Mr. Ritchie Murray
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2026-0154 – Hydro One Networks Inc. Leave to Construct Application – Northeast Power Line Project – Interrogatory Responses

In accordance with Procedural Order No.1, issued July 22, 2026, please find attached an electronic copy of responses provided by Hydro One to interrogatory questions posed by Ontario Energy Board ("OEB") Staff. Intervenor interrogatory responses have been assigned Exhibit I. OEB Staff interrogatories have been assigned Tab 1 of Exhibit I.

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

- **Exhibit I, Tab 1, Schedule 4** – pertaining to requests seeking information regarding the calculation of the Project's annual line losses;
- **Exhibit I, Tab 1, Schedule 7 part h** - pertaining to requests informed by Engineering, Procurement and Construction ("EPC") contract information,
- **Exhibit I, Tab 1, Schedule 8 part c -** pertaining to requests informed by EPC contract information
- **Exhibit I, Tab 1, Schedule 11 part a** - pertaining to requests informed by EPC contract information.

Accordingly, the above-noted responses and related documents are redacted from this public version of the responses to OEB Staff interrogatories which will be posted to the public record of the proceeding.

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 4(b)-(c), 7(h), 8(c), 11(a). With respect to the foregoing requests, by way of separate filing, Hydro One will be filing a motion consistent with the Rules and the Practice Direction.

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

Sincerely,

Pasquale Catalano

OEB STAFF INTERROGATORY - 01

Reference:

1. Exhibit B-1-1, Page 3-6
2. Exhibit B-10-1, Page1-2

Preamble:

Hydro One states that the new transmission line (NEPL or the Project) is expected to be owned by, and included in the rate base of, a future OEB-transmission licensed partnership, which has not yet been finalized. Hydro One further states that transmission line costs will be tracked in its OEB-approved Affiliate Transmission Project (ATP) Regulatory Account pending the formation of the partnership and completion of the required asset transfer and licensing processes.

Hydro One also states that the Project's station costs will remain with Hydro One and are expected to be included in Hydro One's future transmission rate application for the 2028-2032 period.

Interrogatory:

a) Please provide an update on the status of the future partnership and indicate the expected timeline for completion of the partnership structure.

b) Please confirm what transmission line assets associated with the Project, if any, will ultimately be transferred to the future partnership and identify any line-related assets that are currently expected to remain under Hydro One ownership.

Response:

a) Hydro One continues to work closely with the nine First Nations partners to advance the partnership documentation, including the partnership structure. The parties remain committed to finalizing the agreements as soon as possible.

b) Consistent with the OEB's Decision and Order that established Hydro One's ATP Account[1] and Hydro One's First Nations Equity Partnership model, the future partnership is expected to own all the transmission line assets associated with the Project.

[1] EB-2021-0169 – Decision and Order – Issued October 7, 2021

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OEB STAFF INTERROGATORY - 02

Reference:
Exhibit B-2-1, Page 1

Preamble:
Hydro One notes that the NEPL will share a right of way with Hydro One's existing 230 kV transmission circuit (X74P). Hydro One states that the total right of way is 140 metres for both circuits, with the NEPL utilizing 65-70 metres.

Interrogatory:

a) Please clarify the amount of the right of way along the Project route that will be occupied by the X74P circuit.

b) Please provide details of the clearances between the NEPL and the X74P circuit along the shared right of way.

c) Please confirm if all portions of the Project will occupy the existing right of way being used for the X74P circuit? If not, please provide details of the proposed route.

Response:

a) The existing X74P 230 kV transmission circuit is located within an existing transmission corridor that is approximately 140 m wide. The NEPL Project will be constructed within the same corridor and will utilize approximately 70 m of the total corridor's width. The remaining corridor width, approximately 70 m, continues to be occupied by the existing X74P circuit and associated operating clearances.

b) The horizontal separation between the NEPL circuit and the existing X74P circuit was established through detailed ROW and line design studies. The shared corridor is generally 140 m wide and accommodates two nominal 70 m operating envelopes, one for X74P and one for the NEPL circuit. The separation was verified through modelling that considered electrical clearances, access requirements, helicopter operating clearances, and structure security class. The modeled radial clearances between NEPL and X74P facilities were confirmed to satisfy Hydro One design requirements along the entire corridor. Additional design refinements have been incorporated at localized pinch-point areas near Mississagi TS where the corridor narrows, including modifications to the existing X74P configuration to preserve required clearances.

c) As described at Exhibit E, Tab 1, Schedule 1, the new transmission line aligns with the *Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2024*[1]*, under the Planning Act* in so far as the Project makes use of existing infrastructure and facilities. The NEPL Project has been designed to utilize the existing Hydro One transmission corridor that currently contains the X74P circuit for what is essentially the entire transmission line route. The transmission line will parallel the existing X74P circuit for approximately 201 of the total 205 km route. At the western end of the route, near Mississagi TS, the two circuits' alignment departs slightly from the X74P centreline to accommodate its connection into the new 500 kV station facilities. Please refer to Exhibit E, Tab 1, Schedule 1 as well as Exhibit C, Tab 1, Schedule 1 for further details.

[1] Ontario Provincial Planning Statement, 2024, sections 3.3.4 and 3.3.5.

OEB STAFF INTERROGATORY - 03

Reference:
1. Exhibit B-3-1, Attachment 5, Page 3
2. Exhibit B-7-1, Pages 1-3
3. Exhibit H-1-1, Attachment 1, Page 9

Preamble:
Hydro One states that the forecast total capital cost of the NEPL is approximately $1.853 billion, consisting of approximately $1.280 billion for line work and approximately $573 million for station work. Hydro One further states that the current cost estimate is based on an AACE Class 3 estimate and incorporates executed contracts, binding EPC bids, contingencies, tariffs, and other project-specific costs. The IESO's Northeast Bulk Plan estimated the cost of the reinforcement portfolio, including the NEPL, at approximately $1.25 billion to $1.53 billion.

Interrogatory:
a) Please reconcile the current Project cost estimate of $1.853 billion with the planning-level estimate range of $1.25 billion to $1.53 billion referenced in the IESO report.

b) Please provide a detailed breakdown of the factors contributing to the difference between the planning-level estimate and the current Project estimate and quantify the estimated cost impact for each factor.

Response:
a) & b)
The IESO *Need for Northeast Bulk System Reinforcement* Report (the “IESO Report”) references a cost of $1.25-1.53 B[1]. This is the combined cost range for three transmission line projects referenced in the IESO Report:

1. One new single circuit 230 kV line spanning between Wawa TS and Porcupine TS)
2. One new single circuit 500 kV line spanning between Mississagi TS and Hanmer TS, and
3. One new double circuit 230 kV line spanning between Mississagi TS and Third Line TS.

[1] The $1.53B is comprised of planning allowance costs of; $725M, $650M, $150M respectively for the projects 1,2,3 as listed above.

The estimate that underpins the IESO Report was provided by Hydro One as a planning allowance for the Project at $650M based on 2019-unit costing for the line and station termination work (“the IESO Report Planning Allowance”). This was based on the latest unit costing information available at the time without consideration of COVID-19. The IESO Report Planning Allowance predates the issuance of the 2022 IESO Report, the issuance of the OIC and similarly, Hydro One’s designation as transmitter to construct the NEPL Project and thus the initiation of the Project. The IESO Report Planning Allowance is therefore a planning level allowance with volatility even greater than a Class 5 AACE estimate. A planning level allowance estimate is utilized strictly for planning purposes since refining estimates for large transmission infrastructure requires significant time, effort and cost that if otherwise deemed to be necessary, would significantly delay all transmission planning activities.

At the time of sharing the IESO Report Planning Allowance for the NEPL Project, Hydro One advised that further engineering and site investigations would be needed to refine the scope definition, identify additional risks and design details. Specifically, Hydro One outlined that:

a. line costs will vary with the nature of access roads, terrain and soil conditions.
b. line costs exclude right-of-way acquisitions, special configurations, accommodation or conditions.
c. line costs exclude Indigenous community’s consultation.
d. Station Costs may vary based on substation soil, grounding or other electrical arrangement

Since the IESO Report Planning Allowance:

1. costs of critical components for transmission lines have risen dramatically, outpacing CPI inflation
2. the construction labour market has tightened with various jurisdictions looking to modernize their electricity grids
3. protectionist policies of the last two US administrations have increased uncertainty around trade, tariffs and North American supply chains, making the cost and availability of key inputs less predictable
4. the terrain along the NEPL ROW is remote and densely forested; making transportation and vegetation clearing costs a substantial portion of overall project outlays.

These factors were not and could not be included in IESO Report Planning Allowance which was based on limited information. Each of the above-noted factors is further described below as factors 1, 2, 3 and 4 which are supported by a report authored by

Charles Rivers Associates International (the "CRAI Report") which is filed as Attachment 1 to this Schedule.

1. Cost of Critical Components for Transmission Lines

As set out on pages 3-5 of the CRAI Report, transmission material costs have increased significantly since 2019 and at a pace faster than CPI.

Since 2019, Hydro One has experienced high and sustained inflation, with significant increases in the cost of key electrical equipment and materials. These trends are consistent with expert observations on utility costs during the historical period. In the 2025 Total Cost Benchmarking Survey issued by Pacific Energy Group (PEG) on behalf of the OEB, PEG similarly observed:

> unusually rapid inflation in the construction costs of US-based distributors in the years since the pandemic. For example, the Handy Whitman Indexes of Power Distribution Construction costs in the North Atlantic region of the United States have risen drastically in recent years. The summary index for distribution plant in July 2023 was 52% higher than it was in July of 2019 and the line transformers were 86% higher.[2] [emphasis added]

Cost escalation exceeding the OEB's inflationary levels is not unique to Hydro One and remains true when compared across the industry for both transmission and distribution infrastructure. Consequently, escalating historical cost forecasts to current costs may require including escalation factors that exceed the OEB's inflationary levels as OEB inflationary levels may not realistically reflect actual market costs and therefore fail to appropriately escalate historical capital costs for current industry capital cost pressures.[3]

To provide OEB assurance that the forecast cost provided in Exhibit B, Tab 7, Schedule 1 of the Application remains in-line with the preliminary planning allowance in the IESO Report, Hydro One has utilized the OEB's approved Uniform Transmission Revenue Requirement ("UTRR") at the time of the unit costs (2019) and escalated the IESO Report Planning Allowance by the compound annual growth rate of the OEB's approved UTRR to today's date. That compound annual growth rate is then held constant until the forecast in-service date. This detail is shown in Figure 1, below.

[2] Preamble to question B4 in the Construction Cost section of the PEG TCB Survey, issued May 6, 2025.

[3] Hydro One has typically utilized the OEB's inflation factor to escalate historical comparator project costs to the current project.

Line	Figure 1: Adjusted IESO Report Costs	
A	2019 OEB Approved Uniform Transmission Revenue Requirement (UTRR)	$1,652,282,431
B	2026 OEB Approved Uniform Transmission Revenue Requirement (UTRR)	$2,389,605,744
C	Compound Annual Growth Rate of UTRR	**5.41%**
D	IESO Report Planning Allowance	$650
E	Lower Range Forecast Before Escalation of IESO Report Planning Allowance (D - 50%)	$325
F	Upper Range Forecast Before Escalation at IESO Report Planning Allowance (D+100%)	$1,300
G	Total Adjusted Cost in 2029 ($M)	**$785.00**
H	Lower Range Forecast With Escalation of IESO Report to 2029 ($M) (G-50%)	**$460**
I	Upper Range Forecast With Escalation of IESO Report to 2029 ($M) (G+100%)	**$1,570**

The analysis in Figure 1 demonstrates that the IESO Report Planning Allowance of $650M would now be $785M. Even if using the upper limits of the AACE Class 5 ranges (which Hydro One submits is not appropriate[4]), adjusting for this cost escalation variable alone would revise the upper range forecast cost of the Project detailed in the IESO Report to $1,570M.[5] Importantly, this adjusted upper-range cost of $1,570M would not reflect Project-specific costs that were not included in the IESO Report Planning Allowance. These costs significantly contribute to the overall expenditure associated with the delivery of this priority transmission project, namely, terrain and remote site mobilization and work adjustments as further described in Factor 4 – Terrain, below.

These costs (terrain and remote site mobilization) add approximately an additional $480M to the Project's cost relative to a southern Ontario project comparator as described in Exhibit B, Tab 7 Schedule 1. Combining only these two figures ($1,570M for the revised forecast cost and $480M for site-related costs) would increase the IESO Report Planning Allowance to a value that exceeds $2B. Therefore, once cost inflation and only terrain and remote site work variables are considered, it is demonstrated that the forecast cost of the Project is well within the initial planning allowance levels provided in the IESO Report. Given this conclusion, and the unavailability of a detailed estimate comparison, Hydro One will not delve into all other items that were not included in the IESO Report Planning Allowance that may have otherwise contributed to the delta in costs detailed in part a), (e.g., Right of way ("ROW") acquisitions, special configurations, Indigenous consultation).

[4] The estimate that underpins the IESO Planning Estimate Report was provided by Hydro One as a planning allowance for the Project at $650M based on unit costing for the line and station termination work available at the time. It predates the issuance of the 2022 IESO Report, the issuance of the OIC and similarly, Hydro One's designation as transmitter to construct the NEPL Project and thus the initiation of the Project. The IESO Report estimate is therefore a planning level allowance with volatility even greater than a Class 5 AACE estimate

[5] Line I of Figure 1

2. The Construction Labour Market

As set out on pages 6-8 of the CRAI Report, transmission and generation construction has increased recently relative to prior periods, suggesting that labour, contractor capacity and equipment demand could peak across multiple projects at the same time. This is likely to lead to a tighter construction market than Canada has experienced in recent years.

3. US Protectionist Policies

As set out on pages 8-9 of the CRAI report, protectionist policies of the last two US administrations have increased uncertainty around trade, tariffs and North American supply chains, making the cost and availability of key inputs less predictable.

4. Terrain

The Project ROW follows a remote and densely forested area and many of the trees are hardwoods like sugar maple and yellow birch, which are particularly difficult to remove. [6] [7] [8] In addition to the forested areas, the terrain is comprised of rocky segments that increase complexity, and subsequently cost, of the Project's construction and significant elevation changes throughout the length of the line. In particular, the factors described below have a substantial impact on project costs.

4 (a) *Remote Access*

More than 50 kilometers of the route is at least 30 kilometers distant from population centers such as the city of Elliot Lake and the city of Greater Sudbury.[9] Constructing in remote areas means either that workers will spend extensive time 'commuting' down the ROW during the workday, depressing productivity, or in the alternative, remote camps need to be constructed along the ROW in order to accommodate the workers and drive down the 'commuting' time. Additional camp construction, especially given the remote access, will accrue additional costs. While the route of the NEPL line follows an existing ROW, existing access is only capable of supporting operation and maintenance activities, whereas major construction will require more heavy equipment and higher traffic, so additional access will need to be created and existing access will require significant

[6] Hydro One. *Northeast Power Line.* Accessed August 10th, 2026

[7] Government of Ontario. Forest resources of Ontario 2021, Accessed August 12th, 2026.

[8] Government of Ontario. Stage Four – Information Centre: Review of Draft 2020-2030 Algoma Forest Management Plan, Accessed August 12th, 2026.
Stage Four – Information Centre: Review of Draft 2020-2030 Algoma Forest Management Plan. - Google Search

[9] See FN 6.

improvements. Additionally, the transport of heavy materials such as lattice beams, conductors, concrete, and other major items along the remote ROW will incur substantial fuel costs. Ontario diesel prices have been very volatile over the last decade, swinging between CA$0.84 and CA$2.26 per litre.[10]

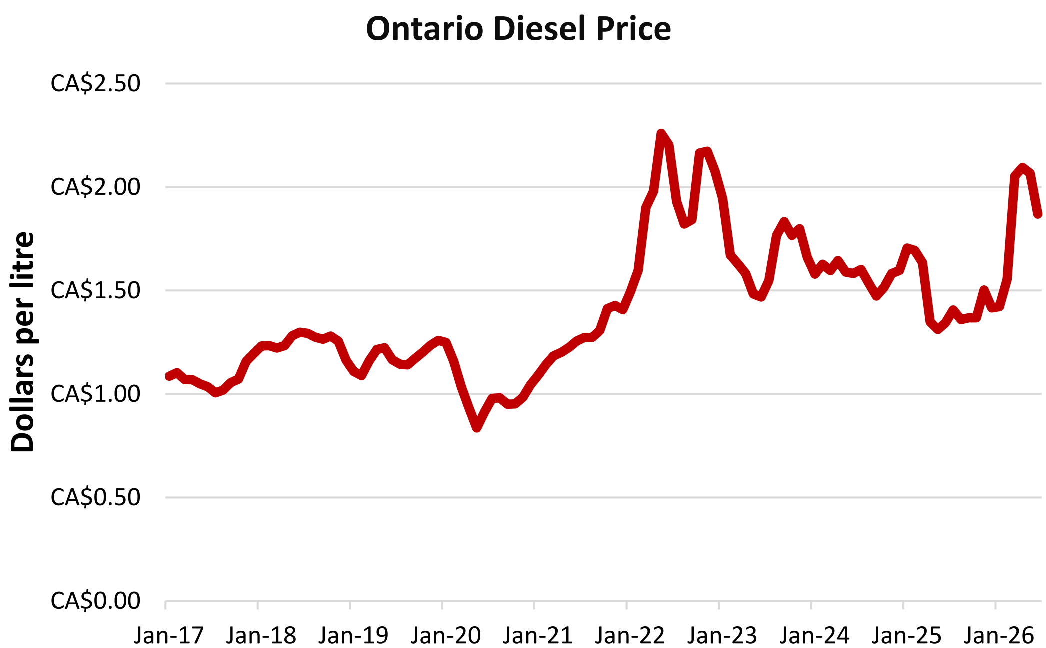

Figure 2: Diesel Cost Increase Since Estimate Creation

The remoteness of the Project's ROW means that roads are sometimes impractical making airlifting all but a requirement to move materials, crews and equipment. However, the costs of this transportation method have also dramatically increased. Similar to diesel prices, aviation fuel prices have more than doubled over the past decade; exhibiting significant volatility between 2021 and 2023.[11]

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[10] Statistics Canada. Table 18-10-0001-01. Monthly average retail prices for gasoline and fuel oil, by geography, Accessed August 13th, 2026.
[11] Statistics Canada. Table 18-10-0266-01. Industrial product price index, by product, monthly, Accessed August 13th, 2026.

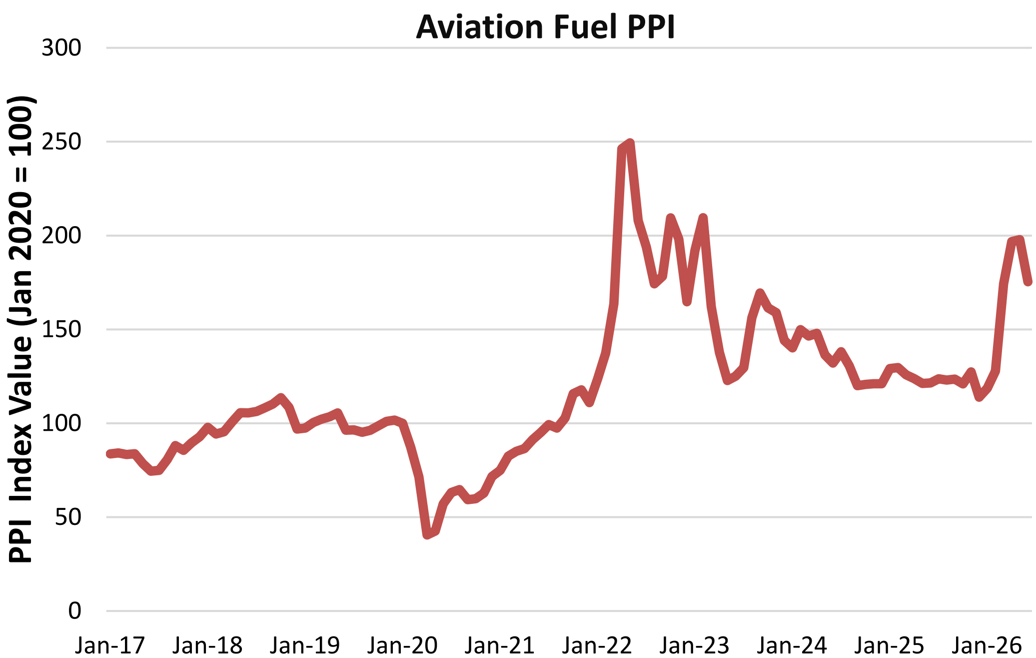

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Figure 3: Aviation Fuel Cost Increase Since Estimate Creation

4 (b) *ROW Clearing and Management in Dense Vegetation*

ROW clearing in a densely forested area will add significant costs to the start of the Project. Vegetation Management costs across Canada have increased in recent years, as the increased demand for Forestry trades has driven up wages significantly beyond other labour categories.[12] Additionally, maintaining a clear ROW over the two-year construction period means that additional labour may be necessary depending on local growth patterns. While the use of guyed structures reduces tower assembly and erection labour-hours, the extension of guy wires beyond the standard stand-alone footprint means that ROW clearing costs will be higher relative to a traditional ROW width.

4 (c) *Uneven and Rocky Terrain*

As elevation changes across the ROW, access roads follow a non-linear route to accommodate rises, cross streams, and avoid natural landscape idiosyncrasies. If the NEPL planned access road will encounter any non-linear route, it may impact:

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[12] BC Hydro. Wildfire prevention and safety work, Accessed August 13th, 2026. See also: Hydro Quebec. Report by the Auditor General – Hydro-Quebec is already working to optimize system maintenance and reduce outages, December 7th, 2022.

1. commute time for construction labourers to reach worksites; and

2. clearing and road construction requirements. There are a large number of water crossings which will require matting, culvert construction, and other remediations, which can be costly. There are also areas where clearing can only be achieved by hand, significantly increasing the associated costs.

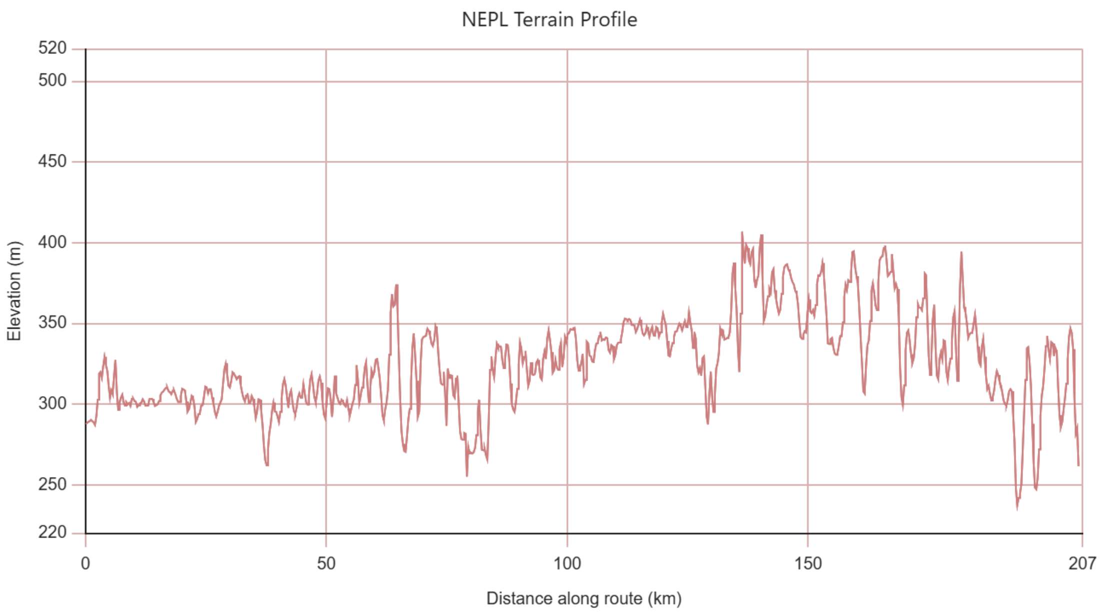

Figure 4: Uneven Terrain Along Entire Distance

In addition to the challenges arising from the uneven terrain, the ROW itself is comprised of rocky terrain, including cliff faces and significant elevation changes comprised of rocks. This has substantial effect on the cost of foundations and grounding.

4 (d) *Construction Season*

Certain Project construction activities may only take during winter months, where heavy equipment can safely navigate the muskeg and loam that surfaces the majority of the ROW. Winter construction poses additional challenges, all of which come with costs, including;

1. Lighting: due to short daylight during winter days, lighting equipment needs to be brought on site so crews can complete a full workday safely.

2. Temperature protection: crews and equipment need to be adequately prepared for and protected from northern Canadian winter temperatures and storms, which can cause damage, delays, and safety incidents if not properly prepared.

Environmental restricted activity periods (“RAPs”), associated with various species, typically inhabiting the Project area, further reduce the available Project construction window. Certain activities, such as, for example, removal of large trees, can only take place, essentially, four months out of a year, warranting fast mobilization of all available resources, running extended work shifts, and rework, associated with removal of stumps, left during the winter clearing periods when this is allowed outside of associated RAPs.

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CRA Charles River Associates

Prepared for:

Hydro One Limited

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Toronto, ON M5G 2P5, Canada

Drivers of Increased Cost Estimate for the Northeast Power Line Project

Prepared by:

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200 Clarendon Street

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Date: 20 August 2026

Disclaimer

The conclusions set forth herein are based on independent research and publicly available material. The views expressed herein are the views and opinions of the authors and do not reflect or represent the views of Charles River Associates or any of the organizations with which the authors are affiliated. Any opinion expressed herein shall not amount to any form of guarantee that the authors or Charles River Associates has determined or predicted future events or circumstances, and no such reliance may be inferred or implied. The authors and Charles River Associates accept no duty of care or liability of any kind whatsoever to any party, and no responsibility for damages, if any, suffered by any party as a result of decisions made, or not made, or actions taken, or not taken, based on this paper. Detailed information about Charles River Associates, a tradename of CRA International, Inc., is available at www.crai.com.

Table of contents

1. Executive Overview

The purpose of this memo is to contextualize Hydro One's cost estimate of $1.853 billion for the Northeast Power Line (NEPL) Project, given the planning-level estimate of $1.25 billion to $1.53 billion referenced in the IESOs *Need for Northeast Bulk System Reinforcement* Report. The initial cost estimates were predicated on 2019 commodity costs and shared with the IESO in 2021/22, at a time when the full extent of the supply chain crisis brought on by COVID-19 was yet to be understood.[1] Since that time, costs of critical components for transmission lines have risen dramatically, far outstripping even the elevated inflation levels experienced over the past five years. At the same time, the construction labour market has tightened as the size of the labour force has failed to keep pace with rising demand for construction labour. Moreover, the protectionist policies of the last two US administrations have increased uncertainty around trade, tariffs and North American supply chains, making the cost and availability of key inputs less predictable. Finally, industry benchmarks from MISO and CAISO support Hydro One's circuit cost normalization. The combination of these varied factors, many of which were not foreseen or foreseeable in the 2019-2022 period, serve to support why Hydro One's current cost estimate for the NEPL Project is higher than preliminary planning estimates.

2. Cost Escalation of Transmission Materials

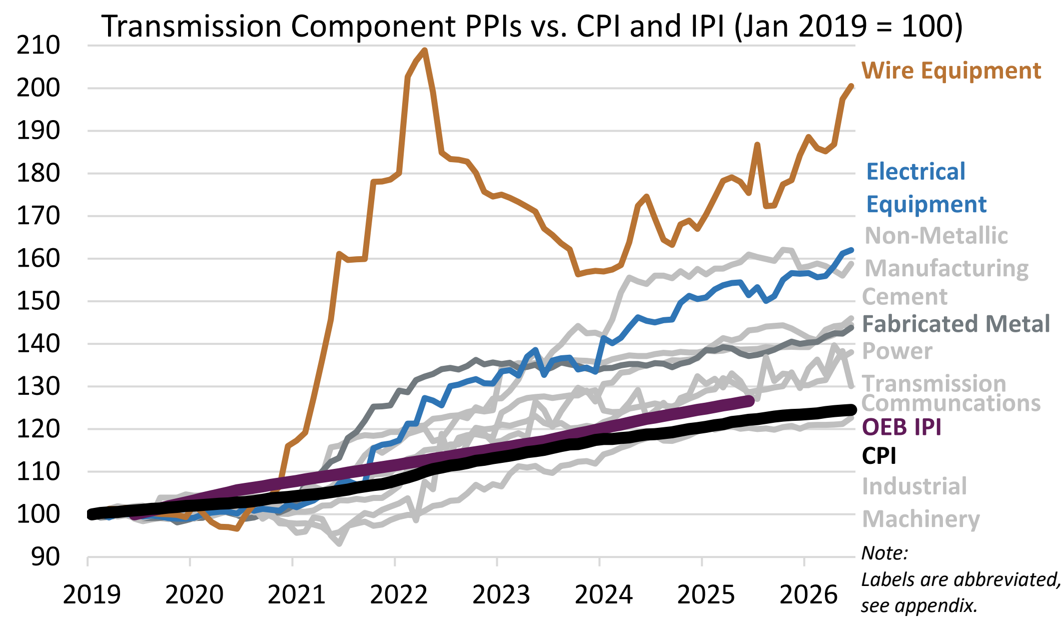
New transmission line construction costs are concentrated in a few categories: construction labour and equipment rentals, engineered equipment, and materials such as fabricated structures. Thus, to understand how costs have evolved over time, it is informative to track relevant indices that measure transmission-specific equipment and labour categories. Between 2019 and 2026, purchasing price indices for transmission components such as electrical equipment, cement, and wires rose much more rapidly than Canada's Consumer Price Index (CPI) and the Ontario Energy Board's (OEB) Input Price Index (IPI) for electric distributors (see Figure 1). These indices increased between 23% and 101% whereas the CPI only rose 25%[2] and the OEB IPI 27%[3] over the same period. Figure 1 spotlights the price indices for three particularly important components – wire equipment, electrical equipment, and fabricated metal. Wire equipment, which covers conductors and cables, saw a 101% increase in its price index between 2019 and 2026. Over the same period, the electrical equipment index, which captures transformers and switchgears, jumped by over 60%, whereas the fabricated metal index, which captures steel towers and hardware, rose nearly 45%.

[1] Board of Governors of the Federal Reserve System. Monetary Policy in the Time of COVID, August 27th, 2021. See also: Bank of Canada. Monetary Policy Report, January 2022.

[2] Statistics Canada. Table 18-10-0256-01. Consumer Price Index (CPI) statistics, measures of core inflation and other related statistics, Accessed August 12th, 2026. See also: Statistics Canada. Table 18-10-0267-01. Individual product price index, by industry, monthly, Accessed August 14th, 2026.

[3] The OEB's IPI is a composite measure calculated annually based on a 30% weight on Ontario's labour costs and a 70% weight on Canada's final domestic demand. The source of the final domestic demand measure is: Statistics Canada. Table 36-10-0106-01. Gross domestic product price indexes, quarterly, Accessed August 19th, 2026. The source of Ontario labour costs is: Statistics Canada, Average weekly earnings by industry, annual, Accessed August 19th, 2026.

Figure 1. Transmission Component Cost Growth Far Outpaces CPI and IPI Benchmarks[4]



This rapid price rise has been accompanied by a pronounced jump in the price volatility of crucial commodities like Aluminum, Copper and Steel (see Figure 2). Steel serves as the primary structural metal for transmission towers, whereas Aluminum and Copper are commonly used in electrical equipment and conductors. The price index for hot rolled Steel rose by 139% between December 2020 and October 2021 as demand rebounded post-COVID while broad supply chain disruptions constrained global steel supplies. The easing of the pressures led to a 20% decline in the same index between June and October 2023. Since June 2025, global supply shortages have led to 40% increases in the price of unwrought Aluminum and Copper. Greater commodity price volatility increases the uncertainty of input prices and the risk premium embedded in supplier contracts, often prompting equipment suppliers who rely on commodity inputs to manufacture a finished product to raise prices.[5]

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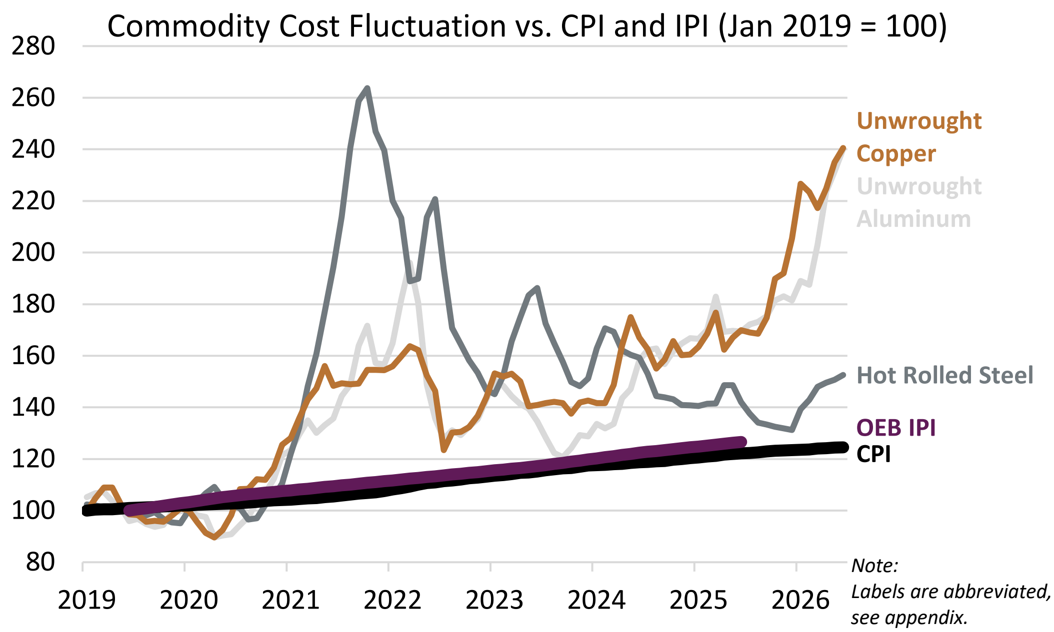
[4] See Table 1 for a description of the underlying data sources.

[5] Statistics Canada. Table 18-10-0266-01. Individual product price index, by product, monthly, Accessed August 13th, 2026.

Figure 2. Price Volatility in Crucial Commodities[6]



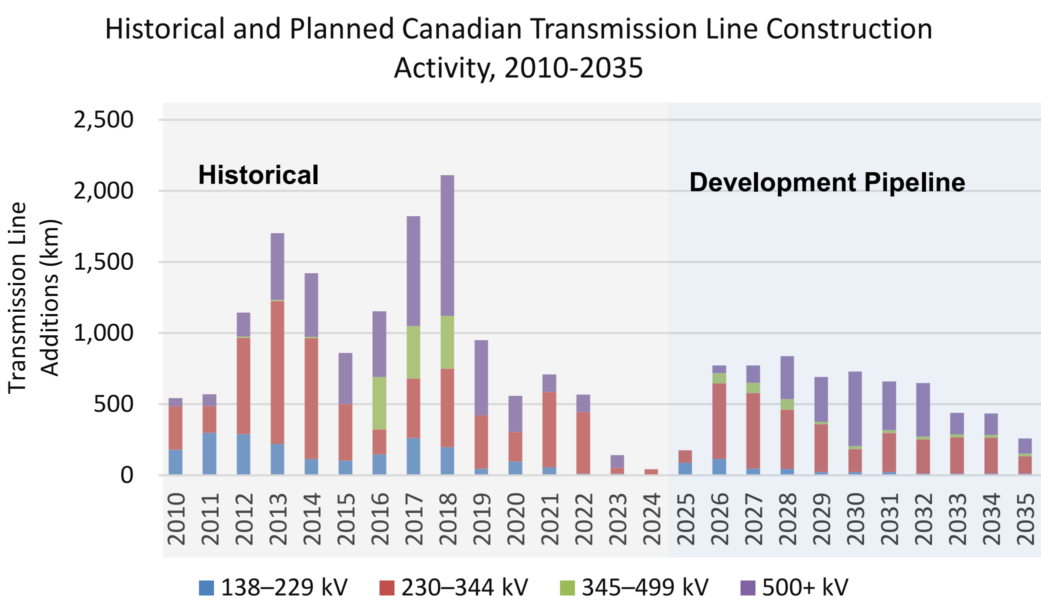
6 See Table 2 for a description of the underlying data sources.

3. Tight Construction Labour Market

3.1. Transmission Buildout

Transmission development across Canada represents a sustained source of construction demand over the next decade. This creates a persistent baseline of demand for skilled trades, specialty contractors and heavy equipment.

Figure 3. Significant Transmission Addition Puts Pressure on Power Construction Market[7]



This planned build in such a concentrated period creates stress to the volume and locality of demand for skilled trades, specialty contractors, engineering resources and heavy equipment.

Ontario, however, differs materially from the national trend. Transmission construction in Ontario since the mid 2020's[8] has been increasing sharply. Those forecasts persist through the early 2030s, driven by a concentrated pipeline of major 230 kV and 500 kV projects, including the Northeast Power Line and other large-scale system reinforcements as identified

[7] Hydro One; IESO; Ontario Energy Board; AESO; AltaLink; ATCO Electric; BC Hydro; SaskPower; Manitoba Hydro; Hydro-Québec; NB Power; Nova Scotia Power; Newfoundland and Labrador Hydro; S&P Global Market Intelligence; CRAI analysis. Project length is distributed across expected construction periods rather than assigned entirely to the in-service year, with projects below 345 kV spread over two years and projects at 345 kV and above spread over three years. Projects without specific in-service dates are distributed across the 2026–2035 forecast period. The analysis includes rebuilds and work along existing rights-of-way, which continue to require construction labour, equipment and contractor capacity.

[8] EB-2023-0198 (Waasigan Transmission Line), EB-2024-0155 (St. Clair Transmission Line), EB 2022-0140 (Chatham x Lakeshore Transmission Line)

by the latest Bulk[9] and Regional Planning[10] activities being initiated by the Independent Electricity System Operator. This significant buildout is underscored by the Ontario government's significant electricity build-out as recently released in the Ontario Integrated Energy Plan[11]. This planned build creates a concentrated period and locality of demand for skilled trades, specialty contractors, engineering resources and heavy equipment.

3.2. Generation Buildout[12]

This Ontario-specific transmission buildout will also occur alongside a significant increase in generation construction, as planned power generation additions provide a meaningful step-change in construction activity relative to recent years. Planned Canadian generation additions average approximately 10.4 GW per year from 2026 through 2031, compared with approximately 2.6 GW per year from 2010 through 2025, an increase of approximately 302% (see 4).

The concentration of planned generation projects through the early 2030s suggests that labour, contractor capacity and equipment demand could peak across multiple projects at the same time. Even allowing for delays or project attrition, the scale of the pipeline points to a materially tighter construction market than Canada has experienced in recent years. This will likely have a strong impact on construction labour and contractor costs during the NEPL construction period.

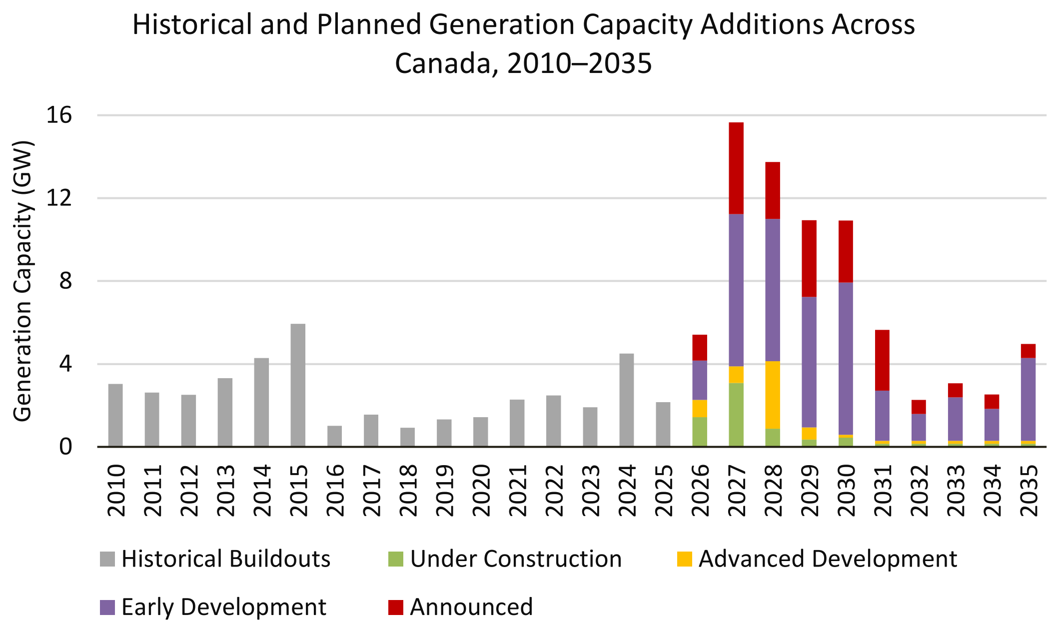
9 https://www.ieso.ca/Get-Involved/Bulk-Planning/Overview

10 https://www.ieso.ca/get-involved/regional-planning/about-regional-planning/overview

11 https://www.ontario.ca/files/2025-07/mem-energy-for-generations-en-2025-07-18.pdf

12 S&P Capital IQ Pro, S&P Global Market Intelligence; CRAI analysis. Projects with no in-service year have been distributed across the forecast period.

Figure 4. Significant Generation Construction Puts Pressure on Power Construction Market



The combination of a steady ongoing transmission buildout and a sharply rising generation pipeline will therefore increase competition for the same power sector-oriented highly skilled trades, the utility construction workforce, and contractor capacity, tightening the construction labour market during periods of concurrent activity.

4. The Impact of Trade Pressures, Geopolitics, and U.S. Protectionist Policies

The trade war launched by the Trump administration on Canada has made long-term transmission investment more challenging to execute. Citing the 'extraordinary threat posed by illegal aliens and drugs', the administration imposed a 25% tariff on imports from Canada and Mexico on February 1st, 2025.[13] Canada retaliated by imposing a 25% tariff on US steel, aluminum, and many manufactured goods.[14] These reciprocal tariffs likely increased landed costs for Canadian utilities and developers looking to source transformers, electrical components, or related equipment from the US. Developers looking to avoid tariffs would have been forced to seek out alternative suppliers, potentially increasing construction and financing costs. Even if a transmission component was not directly tariffed by name, Canadian manufacturers have broadly faced higher prices for tariffed steel and aluminum inputs and pass those costs on transmission developers.

[13] The White House. Fact Sheet: President Donald J. Trump Imposes Tariffs on Imports from Canada, Mexico and China, February 1st, 2025.

[14] Government of Canada. List of products from the United States subject to 25 per cent tariffs effective March 13, 2025, Accessed August 19th, 2025.

The 25% tariff imposed by the Trump administration was the opening salvo of the current trade war. In June 2025, the administration raised tariffs on imported steel and aluminum products to 50%, forcing Canada into raising reciprocal tariffs.[15] In 2026, the administration threatened to further raise tariffs to 100% if Canada agreed to a normalization of trade relations with China.[16] Overall, the arbitrary and unpredictable nature of the recent trade war increases uncertainty, discourages long-term cross-border trade, and ultimately raises the overall cost of transmission buildout.

5. Industry Benchmarks Support Hydro One's Normalization Factor

Hydro One applies a 60% factor to normalize the costs of the 500 kV double-circuit Heartland and Bruce to Milton projects to a single-circuit equivalent. Hydro One selected this factor based on industry cost benchmarks, including data from a variety of Californian 500 kV lattice-tower projects and MISO 345 kV transmission line cost estimates. The MISO cost estimation guides are regularly updated and are generally accepted as industry references, and are often used by utilities outside of MISO to compare cost ranges and rough cost factors.

Across 15 MISO state-level 345 kV observations, single-circuit costs average 60.9% of corresponding double-circuit costs, with a median of 60.3%. The observations are tightly concentrated between 58.2% and 64.1%, placing Hydro One's 60% assumption near the center of the MISO benchmark range.[17] The MISO data lends further weight to the 60% factor, as even though terrain, vegetation, population density, topography, and soil conditions, among other factors, vary widely across the 15 states covered by MISO, the observations remain closely clustered around 60%. The California 500 kV benchmarks show greater variation, but similarly support a normalization factor in the range selected by Hydro One. Hydro One's 60% assumption falls between the average and median estimates of the observed California range – and if anything, Hydro One's use of 60% is more conservative than using a lower factor which could be justified by the Californian data.[18] Taken together, the MISO and California benchmarks provide external benchmark support for Hydro One's selected factor as it falls within the observed range (see 6).

These benchmarks are most relevant to assessing the relative cost relationship between single- and double-circuit configurations, rather than absolute construction costs in Northern Ontario. Project-specific conditions such as terrain, access and constructability can materially affect absolute transmission costs and are addressed separately in Hydro One's comparator

15 The White House. Fact Sheet: President Donald J. Trump Strengthens Tariffs on Steel, Aluminum, and Copper Imports, April 2nd, 2026.

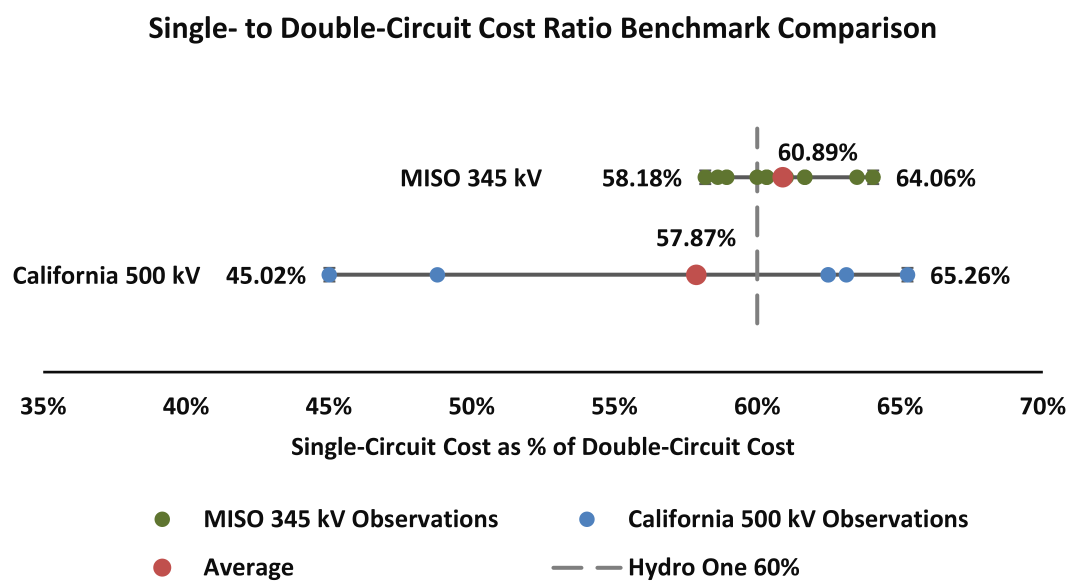
16 Politico. Trump threatens 100 percent tariffs on Canadian imports in response to new trade deal with China, January 24th, 2026.

17 MISO. Transmission Cost Estimation Guide for MTEP24, May 1, 2024, Tables 4.1-1 and 4.1-2; CRAI analysis.

18 California Independent System Operator 2025 Unit Cost Guides; CRAI analysis of DCRT, DesertLink, GridLiance West, Horizon West Transmission, LS Power Grid California, and Southern California Edison 500 kV lattice-tower costs.

methodology.[19][20] Hydro One explicitly adjusts its comparator analysis for terrain and other technical differences, while MISO recognizes terrain as significant transmission-line cost drivers.

Figure 5. MISO and California benchmarks provide external support for Hydro One's Cost Normalization



[19] See FN 14.

[20] MISO. Transmission Cost Estimation Guide for MTEP24, May 1, 2024, Tables 4.1-1 and 4.1-2; CRAI analysis.

Appendix A: Statistics Canada Data Used for Figure 1 and Figure 2

Table 1. Data Series Used from Statistics Canada's Tables 14-10-0204-01, 18-10-0256-01, 18-10-0267-01 and 36-10-0106-01 in Figure 1

Figure 1 Label	NAICS Code	NAICS Code Short Description
CPI	Measure of core inflation based on a weighted median approach, CPI-median (index, 198901=100)	
OEB IPI	• Final domestic demand • Industrial aggregate excluding unclassified businesses	
Glass Products	3272	Glass and glass product manufacturing
Cement	3273	Cement and concrete product manufacturing
Non-Metallic Manufacturing	3279	Other non-metallic mineral product manufacturing
Fabricated Metal	332	Fabricated metal product manufacturing
Industrial Machinery	3332	Industrial machinery manufacturing
Power Transmission	3336	Engine, turbine and power transmission equipment manufacturing
Communications	3342	Communications equipment manufacturing
Electrical Equipment	3353	Electrical equipment manufacturing
Wire Equipment	33592	Communication and energy wire and cable manufacturing

Table 2. Data Series Used from Statistics Canada's Table 18-10-0266-01 in Figure 2

Figure 2 Label	NAPCS Code	NAPCS Code Short Description
Hot Rolled Steel	31211	Hot-rolled iron or steel products
Unwrought Aluminum	32111	Unwrought aluminum and aluminum alloys
Unwrought Copper	322	Unwrought copper and copper alloys

Appendix B: Detailed NAICS and NAPCS Code Descriptions

Table 3. Description of NAICS Series Referenced in Table 1[21]

NAICS Code	NAICS Code Short Description	NAICS Code Long Description
3272	Glass and glass product manufacturing	This industry group comprises establishments primarily engaged in manufacturing glass and glass products.
3273	Cement and concrete product manufacturing	This industry group comprises establishments primarily engaged in manufacturing hydraulic cement, ready-mix concrete, concrete bricks, pipes and blocks, and other concrete products.
3279	Other non-metallic mineral product manufacturing	This industry group comprises establishments, not classified to any other industry group, primarily engaged in manufacturing non-metallic mineral products.
332	Fabricated metal product manufacturing	This subsector comprises establishments primarily engaged in forging, stamping, forming, turning and joining processes to produce ferrous and non-ferrous metal products, such as cutlery and hand

[21] Statistics Canada. *North American Industry Classification System (NAICS) Canada 2022 Version 1.0.* Release date: January 25th, 2024. https://www150.statcan.gc.ca/n1/en/pub/12-501-x/12-501-x-2022001-eng.pdf?st=OjiFcy3V.

		tools, architectural and structural metal products, boilers, tanks and shipping containers, hardware, spring and wire products, turned products, and bolts, nuts and screws.
3332	Industrial machinery manufacturing	This industry group comprises establishments primarily engaged in manufacturing machinery designed for use in specific manufacturing industries.
3336	Engine, turbine and power transmission equipment manufacturing	This industry group comprises establishments primarily engaged in manufacturing turbines and turbine generator sets; internal combustion engines (except automotive gasoline and aircraft); and speed changers, industrial high speed drives and gears. Establishments primarily engaged in manufacturing wind- and solar-powered turbine generators and windmills for generating electric power are included.
3342	Communications equipment manufacturing	This industry group comprises establishments primarily engaged in manufacturing equipment used to move signals electronically over wires or through the air, such as telephone apparatus, radio and television broadcast equipment, and satellite communications equipment.
3353	Electrical equipment manufacturing	This industry group comprises establishments primarily engaged in manufacturing equipment that generates and distributes electrical power.
33592	Communication and energy wire and cable manufacturing	This industry comprises establishments primarily engaged in manufacturing insulated communications and energy wire and cable, made from purchased non-ferrous wire and optical fibres.

Table 4. Description of NAPCS Series Referenced in Table 2[22]

NAPCS Code	NAPCS Code Short Description	NAPCS Code Long Description
31211	Hot-rolled iron or steel products	This class comprises hot-rolled iron or steel products.
32111	Unwrought aluminum and aluminum alloys	This class comprises unwrought aluminum and aluminum alloys.
322	Unwrought copper and copper alloys	This group comprises unwrought copper and copper alloys.

[22] Statistics Canada. *North American Product Classification System (NAPCS) Canada 2022 Version 1.0.* Release date: August 10th, 2023. https://www150.statcan.gc.ca/n1/en/pub/12-003-x/12-003-x2022001-eng.pdf?st=siQzWBgW.

Appendix C: Retrieving Data Used in Figure 1 and Figure 2

Table 5. Retrieving Data Series Used in Table 1

Description
• Go to Statistics Canada's Table: 18-10-0267-01, *Industrial product price index, by industry, monthly* dataset: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1810026701.
• **Set Geography to Canada.**
• Include the following North American Industry Classification System (NAICS) data series: o Glass and glass product manufacturing [3272] o Cement and concrete product manufacturing [3273] o Other non-metallic mineral product manufacturing [3279] o Fabricated metal product manufacturing [332] o Industrial machinery manufacturing [3332] o Engine, turbine and power transmission equipment manufacturing [3336] o Communications equipment manufacturing [3342] o Electrical equipment manufacturing [3353] o Communication and energy wire and cable manufacturing [33592]
• Set Reference period to 'From: January 2019' to 'To: June 2026'.
• Alternatively, this data can be accessed at the following link: https://www150.statcan.gc.ca/t1/tbl1/en/cv!recreate.action?pid=1810026701&selectedNodeIds=2D150,2D152,2D160,2D178,2D207,2D215,2D224,2D243,2D247&checkedLevels=0D1&refPeriods=20190101,20260601&dimensionLayouts=layout2,layout3,layout2&vectorDisplay=false.

Table 6. Retrieving Data Series Used in Table 2

Description
• Go to Statistics Canada's Table: 18-10-0266-01, *Industrial product price index, by product, monthly* dataset: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1810026601.
• **Set Geography to Canada.**

• Include the following North American Product Classification System (NAPCS) data series: ○ Hot-rolled iron or steel products [31211] ○ Unwrought aluminum and aluminum alloys [32111] ○ Unwrought copper and copper alloys [322]
• Set Reference period to 'From: January 2019' to 'To: June 2026'.
• Alternatively, this data can be accessed at the following link: https://www150.statcan.gc.ca/t1/tbl1/en/cv!recreate.action?pid=1810026601&selectedNodeIds=2D161,2D171,2D172&checkedLevels=0D1&refPeriods=20190101,20260601&dimensionLayouts=layout2,layout3,layout2&vectorDisplay=false.

Table 7. Retrieving CPI Data Series Used in Table 1 and Table 2

Description
• Go to Statistics Canada's Table: 18-10-0256-01, *Consumer Price Index (CPI) statistics, measures of core inflation and other related statistics – Bank of Canada definitions* dataset: https://www150.statcan.gc.ca/t1/tbl1/en/cv.action?pid=1810025601.
• **Set Geography to Canada.**
• Set Alternative measures to 'Measure of core inflation based on a weighted median approach, CPI-median (index, 198901 = 100)'
• Set Reference period to 'From: January 2019' to 'To: June 2026'.
• Alternatively, this data can be accessed at the following link: https://www150.statcan.gc.ca/t1/tbl1/en/cv!recreate.action?pid=1810025601&selectedNodeIds=2D10&checkedLevels=0D1&refPeriods=20190101,20260601&dimensionLayouts=layout2,layout3,layout2&vectorDisplay=false.

OEB STAFF INTERROGATORY - 04

Reference:

1. Exhibit B-5-1, Pages 1-4
2. Exhibit B-7-1, Table 3, Page 12

Preamble:

Hydro One states that it undertook an analysis of four conductor alternatives and conducted a 50-year net present value (NPV) analysis. This analysis was completed using varying energy prices of $53.16/MWHR, $60/MWHR, and $120/MWHR, and a capacity price of $164,052/MW, consistent with Hydro One's Line Loss Guideline. Hydro One also factored in annual line losses and losses at system peak in its analysis. This analysis let Hydro One select Alternative #2 (4-795 kcmil ACSR) as the conductor for the Project.

Interrogatory:

a) Please explain how Hydro One determined the energy prices and capacity price to use in its analysis and provide any assumptions that were used in making these selections.

b) What calculations were used to determine the values of "Annual Losses (MWHR)" and "Losses at System Peak (MW)" shown in Table 2 at Reference 1? Please provide an excel sheet showing what calculations and formulas were used to determine these values as well as all assumptions made.

c) Please provide an excel sheet showing the complete calculations used in conducting the Net Present Value sensitivity analysis, which includes all formulas used.

d) At Reference 2, Hydro One shows in the Table that the selected conductor for the Project is the "4 x 732 kcmil ACSR "Drake"". This contradicts the information shown at Reference 1 where the Alternative selected was stated as "4-795 kcmil ACSR". Please confirm what conductor was selected as the alternative and explain any reasons for the differences.

Response:

Please note that all attachments referenced in this response have been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

a) The Energy and Capacity Price used in the assessment included at Exhibit B, Tab 5, Schedule 1 is consistent with the values contemplated in Hydro One's OEB-approved Transmission Line Loss Guideline that was developed in concert with the IESO's own Transmission Planning Guideline for Consideration of Transmission System Losses in the Evaluation of Plan Alternatives that was issued in June 2023[1] (the "IESO Guideline").

The Energy Price of \$53.16/MWh is defined in the Ontario Electricity Market Price by the OEB's most recent Regulated Price Plan – Price Report.[2] The Capacity Price is based on the Reference Price from the IESO's Capacity Auction as per the IESO guideline.

The Capacity Auction Reference Price of \$164,052MW/year reflects the 2024 Capacity Auction Reference Price of \$651MW/business day[3]. The value is annualized by multiplying by business days in a year (252 days) consistent with the IESO Guideline:

$$\$651\text{MW/d} \times 252 \text{ bd/year} = \$164{,}052 \text{ MW/YR}$$

Further to this, a sensitivity at higher plausible energy prices was also used to verify the impact of higher price on the conductor selection.

b) To perform the loss evaluation for the NEPL Project, a detailed model of the predicted flows on the circuit were established as provided at Attachment 1 of this Schedule. This model replicated 8760hr of typical flow on the circuit scaled to a flow limit[4] of what would be expected on the new line which allowed analysis to support the conductor's evaluation. The new 500 kV transmission line is a greenfield facility with no historical flow data available for reference. However, the 230 kV circuit, X74P, connects to the same terminal stations and has no tapped connections. As a result, its loading profile is expected to be representative of the new 500 kV circuit, which will operate in parallel along the same corridor. The X74P flow profile was therefore used as a proxy and scaled to a MW loading level corresponding to the proportional power flow anticipated on the new 500 kV line after all Northeast bulk system projects are completed (as identified in IESO report, "Need for Northeast Bulk System Reinforcement" which is included at Attachment 1 of Exhibit H, Tab 1, Schedule 1).

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[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Transmission-Planning-Guideline-Transmission-Losses.pdf
[2] Regulated Price Plan - Price Report, Page 12, Table 1 - Issued October 17, 2025
[3] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/cae/cae-20240725-engagement-presentation.pdf
[4] System Flows as defined in IESO report and filed evidence titled, "Need for Northeast Bulk System Reinforcement"

For purpose of the study, the system peak hour[5] was correlated to a MW flow and corresponding MW loss for that specific hour. This value was used as "Losses at System peak (MW)"[6]. Annual Losses (MWHR) were calculated by summing the MW losses for each hour of the new flow based on the detailed model.

For the line loss excel model, please refer to Attachment 2 of this Schedule.

c) For the Net Present Value sensitivity analysis, please refer to Attachments 3-6 of this Schedule.

d) Hydro One confirms that conductor selected and procured for the project is 4-795 kcmil ACSR.

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[5] At the time of conductor evaluation, a full calendar year of full-year of data was available from January 1, 2024 to December 31, 2024. System Peak was observed at July 19, 2024 17:00hrs

[6] Power Loss (MW) = $3*I^2R$ where R is the resistance of the conductor, I = Amps flowing on the conductor.

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TRANSMISSION LOSSES WORKBOOK DETAILED

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

TRANSMISSION LOSSES WORKBOOK

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

LINE LOSS ALTERNATIVE NPV MODEL - ALT 1

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

LINE LOSS ALTERNATIVE NPV MODEL - ALT 2

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

LINE LOSS ALTERNATIVE NPV MODEL - ALT 3

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

LINE LOSS ALTERNATIVE NPV MODEL - ALT 4

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

OEB STAFF INTERROGATORY - 05

Reference:

1. Exhibit B-6-1, Pages 1-2
2. Draft Northeast Power Line Environmental Report, February 2026

Preamble:

Hydro One states that the NEPL Regulation established requirements for Hydro One to fulfill in order to proceed with the Project. These requirements were addressed in the draft Environmental Report (ER) Hydro One made accessible on its website.

Further, Hydro One states that the Project will bring employment, training and business opportunities to the region for both Indigenous and non-Indigenous communities, governments and businesses.

Interrogatory:

a) In Reference 2, Hydro One states that, "Hydro One will address all review comments and concerns made on the Draft ER and issue a Final ER". Please provide an update regarding Hydro One's progress of addressing any comments and concerns made on the Draft ER.

b) Please provide a status update on the Final ER. If the Final ER has been published, please provide a copy to the OEB.

c) Please expand on how the Project will support economic growth in the region and provide examples to substantiate the employment, training and business opportunities that Hydro One mentions will be created by the Project at Reference 1.

Response:

a) The ER has been finalized and is available on Hydro One's project website. Comments and concerns made on the Draft ER have been incorporated into the final version of the ER. The Environmental Process has now been completed for the Project.

b) The Project's Final ER has been published and is available on Hydro One's project website[1].

c) As described in Exhibit I, Tab 1, Schedule 14, the NEPL Project is identified in the Integrated Energy Plan as a key project necessary to unlock opportunities in Northern

[1] Northeast Power Line | Hydro One

Ontario and an example of Indigenous economic participation in transmission projects.[2] The Project has also been identified as a priority transmission project in the Order in Council issued October 19, 2023 by the Lieutenant Governor in Council ("OIC") found at Exhibit B, Tab 3, Schedule 1, Attachment 2. As described therein, the Province of Ontario considers it critical to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to support economic growth and electrification initiatives throughout Northeastern and Eastern Ontario.

The OEB's Procedural Order for this proceeding states that need and consideration of alternatives are not at issue in this proceeding because the OIC declares the Project as a priority project:

> *The OEB will use the standard issues list but* ***is excluding the standard issues relating to need and the consideration of alternatives*** *(see Schedule B) [emphasis added]. This is because by an Order in Council (OIC) dated October 19, 2023, the Lieutenant Governor in Council declared the Project as a priority project under section 96.1 of the OEB Act. In accordance with section 96.1(2) of the OEB Act, the OEB accepts that construction of the Project is needed. Further, it is a condition of Hydro One Networks' electricity transmission licence to develop and seek approvals related to the Project and that development of the Project accord with the project scope and timing recommended by the Independent Electricity System Operator (IESO).*[3]

The manner in which the Project supports economic growth is therefore not at issue in this proceeding as the need for the Project, namely to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to support economic growth and electrification initiatives throughout Northeastern and Eastern Ontario, has been established by the Provincial government and accepted by the OEB.

[2] mem-energy-for-generations-en-2025-07-18.pdf – pp. 73 and 135
[3] OEB Procedural Order No. 1, July 22, 2026, EB-2026-0154, p. 2

OEB STAFF INTERROGATORY - 06

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

Preamble:
Reference 1 lists the Line and Station costs associated with the Project, as reproduced below:

Table 1 - Line Cost

	Estimated Cost ($000's)
Materials	224,957
Labour	293,546
Equipment Rental & Contractor Costs	521,730
Sundry	46,020
Contingencies	70,645
Overhead	23,224
Allowance for Funds Used During Construction	98,651
Real Estate	1,155
Total Line Work	**$1,279,928**

Table 2 - Station Cost

	Estimated Cost ($000's)
Materials	192,184
Labour	92,572
Equipment Rental & Contractor Costs	99,822
Sundry	36,385
Contingencies	66,509
Overhead	37,098
Allowance for Funds Used During Construction	48,005
Real Estate	670
Total Transformer Station Work	**$573,245**

Interrogatory:

a) Hydro One states that overhead costs for the Project were charged through an ECI-EPC overhead capitalization rate for line costs and Hydro One's standard overhead capitalization rate for station costs. Please:
   1. Explain the methodology used to determine the overhead costs for the line and stations costs for the Project.
   2. Provide an excel sheet showing all values and formulas used in the calculation.

3. Explain how these costs relate to the ECI-EPC methodology.

b) Please provide a breakdown of the overhead costs between direct overheads and indirect overheads for line and station costs. If this cannot be done by Hydro One, please explain why.

c) Hydro One stated that AFUDC was 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. Please provide an excel sheet showing all values and formulas used in the calculation of AFUDC and further explain the methodology used in the calculation.

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

e) Please describe how the contingency cost estimate for the Project compares to contingency cost estimates developed for projects of similar size and complexity. Please discuss any differences or similarities in costs between these projects and the NEPL.

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 that has been established in previously approved leave to construct applications[1], 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. The results of the calculation of the overhead costs in Microsoft Excel format are provided in Attachment 1 of this Schedule.

b) As outlined in Exhibit B, Tab 7, Schedule 1, Footnote 2, the overhead costs in Table 1 and Table 2 relate are all considered indirect overheads.

c) Please refer to Attachment 1 of this Schedule.

[1] EB-2023-0198 and EB-2024-0155. A report completed by Atrium Economics to support the overhead methodology is specifically provided at Exhibit B, Tab 7, Schedule 1 of EB-2023-0198.

d) 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 scores and ranks 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.

e) Please refer to Table A 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 A - Contingency Cost Comparison

	NEPL	**Bruce to Milton**[2]	**Waasigan – Phase 1**[3]	**SCTL**[4]
Line Cost	6%	6%	10.5%	8.4%
Station Cost	12%	9%	11.2%	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 given size, complexity and geographic location, 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.

[2] EB-2007-050 – Leave to Construct Application - Exhibit B, Tab 4, Scheule 1
[3] EB-2023-0198 – Leave to Construct Application – Exhibit B, Tab 7, Schedule 1
[4] EB-2024-0155 – Leave to Construct Application - Exhibit B, Tab 7, Schedule 1

OVERHEAD AND AFUDC COST ESTIMATE CALCULATION – NEPL PROJECT

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 07

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

Preamble:
Hydro One states that the Project cost estimate is based on a fixed-price EPC contractor bid. Further, Hydro One notes that as of the date of the application filing the EPC bids have been short-listed and evaluations and negotiations with short-listed EPC contractors are ongoing to determine the successful EPC bidder. Hydro One also states that a full EPC approach was selected for STATCOM-specific work at the stations.

Interrogatory:

a) Please provide an update on the EPC contractor selection process. Has the successful EPC contractor been selected?

b) If the successful EPC contractor has been selected, please clarify if there are any changes to the proposed costs that have been stated in the application.

c) Please provide an update on the EPC process for the STATCOM-specific work.

d) Please discuss how the EPC contractor was selected among different EPC contractors for both line and station work. Please include a list of the specific functions the contractors were assessed on.

e) Please discuss how Hydro One determined that utilizing the successful contractor's bid is more cost-effective than Hydro One performing the work itself.

f) Please clarify how the Project cost was estimated based on the fixed-price EPC contract, and why the cost estimate reflects market price.

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

h) Please provide a breakdown of the fixed-price EPC contract by line costs and station costs. Please clarify if this cost is included in the Project costs shown in Tables 1 and 2 of Exhibit B, Tab 7, Schedule 1.

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

Response:

a) Yes, the selection has been completed for the NEPL Project.

b) There are no changes to the proposed EPC contractor costs identified in the application.

c) The EPC contracts for the STATCOM-specific work are in the final stages of commercial negotiations with the selected EPC for both Algoma TS and Mississagi TS 230 kV STATCOMS. Please note that the STATCOM work was included for contextual purposes only as it relates to negotiations and pursuit of a full EPC delivery at the stations affected by both the NEPL Project and the future North Shore Link Project. However, the STATCOM work is not part of the station scope of work for the NEPL Project and is not included in any works detailed in Exhibit C, Tab 1, Schedule 1 or the Project Overview outlined in Exhibit B, Tab 2, Schedule 1. Similarly, that STATCOM scope is not included in any costs detailed in Exhibit B, Tab 7, Schedule 1. The scope and costs associated with the STATCOM work at the affected stations will be detailed in the future leave to construct application for the North Shore Link Project.

d) The EPC selection process for the transmission line component followed the two step ECI-EPC process as noted in Exhibit B, Tab 7, Schedule 1 page 2. Following the receipt of the independent competitive proposals from the qualified EPC contractors who participated in the ECI phase, these proposals have been independently evaluated and scored by Hydro One's integrated technical and commercial evaluation team. This team included representatives of affected Hydro One lines of business and disciplines, such as Outage Planning, Environmental, Health and Safety, Indigenous Relations, Supply Chain, Commercial, as well as representatives of Hydro One's Owners Engineer and Project Management Office team. Technical evaluation criteria included but were not limited to the completeness of the proposal, past performance during ECI phase as well as on other projects; ability to meet or exceed project requirements, including environmental specifications; Canadian content; commitment to Indigenous engagement and participation plan; maturity of design and outage plan. Commercial evaluation criteria included price as well as exceptions to commercial and technical requirements.

The winning bid for the transmission line work scored highest in technical evaluations as well as offered the lowest price.

The EPC selection process for the stations component included all Hydro One pre-qualified station vendors of record who were invited to participate in the bidding process. The NEPL station scope was divided into three components: Hanmer TS, Mississagi 230 kV Phase 1, and the new Mississagi 500 kV station. Contractors were permitted to bid on any or all components, based on their capacity and interest.

Bids were evaluated through a structured technical and commercial assessment process involving multiple stakeholders and based on established evaluation criteria. Evaluation factors included technical capability and station design expertise, relevant experience, key personnel qualifications, Indigenous and Canadian content, pricing, and proposed assumptions and exclusions.

Following the initial evaluation, negotiations were conducted with all proponents to further assess risks, opportunities, and value. Upon completion of this process, the Mississagi and Hanmer scope was awarded to separate EPC contractors. The award decisions reflected not only the submitted pricing but also opportunities for cost savings and risk mitigation achieved through the selected contracting strategy and scope bundling approach.

e) The increasing volume of projects being executed by Hydro One necessitates the use of EPC contractors to supplement available resources and support project schedule commitments. The EPC delivery model provides certainty with respect to project cost and schedule through clearly defined contractual obligations and accountability mechanisms. Achieving the in-service date as planned also results in significant savings by reducing financing and interest-related costs. In addition, leveraging EPC resources enables Hydro One's internal construction workforce to focus on other priority and demand-driven projects, improving overall portfolio execution capacity.

f) At the time of filing the application, the forecast cost provided at Exhibit B, Tab 7, Schedule 1 was informed by the EPC contract bids received. The agreements underpinning the successful EPC bid were anticipated to be finalized, however the terms and conditions of the executed EPC agreement were not yet finalized at the time of filing. As described in part a) of this response, the contractors have now been selected and as described in part b) of this response, there is no update to the forecast cost detailed in Exhibit B, Tab 7, Schedule 1. Please refer to part d) of this response for further information on why the cost estimate reflects market pricing.

g) The fixed-price EPC contract significantly reduces uncertainty and the risk of cost overruns associated with execution of the defined project scope; however, it does not eliminate all cost overrun risks. To address this, Hydro One worked collaboratively with the EPC contractors to identify and allocate project risks into three categories:

1. **Contractor-owned risks**: Risks under the EPC contractor's control for which the EPC is responsible for.
2. **Hydro One-owned risks**: Risks that are the sole responsibility of Hydro One, such as regulatory approvals that may affect the timing of construction commencement. These risks are accounted for in the project contingency held by Hydro One.
3. **Excluded Risks**: Risks that are impossible to quantify due to the unlikelihood or uncertainty of occurrence, which include: Labour disputes; Safety or environmental incidents; Significant changes in costs and/or availability of materials and equipment outside Hydro One's control, including impacts from changes in government policy, introduction of new tariffs in addition to those tariffs already in effect, or disruptions arising from geopolitical instability; Cost of disposal/remediation of contaminated soil and hazardous materials found on the ROW; or any other unforeseen and potentially significant event/occurrence. These risks will be quantified if and as they arise and are not included in the project contingency.

The project team will work with its various stakeholders and vendors to avoid and / or mitigate potential events that could result in cost overruns. If an event occurs that has an impact on cost, the structure above will be applied and the impact will be borne by the Hydro One or the EPC depending on whether it is a Contractor or Hydro One owned risk. If there is a material event that results in an excluded risk occurring that could not be avoided or mitigated, the project will endeavor to manage the impact within the existing budget and will update the OEB if there is a material impact as per the OEB's standard conditions of approval for leave to construct.
Please refer to part d) of Exhibit I, Tab 1, Schedule 6 for further information on how the contingency estimate was developed.

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

Cumulatively, the EPC contracts, for Stations and Lines, excluding interest AFUDC and overhead, are forecast to represent approximately [redacted] of the direct costs or [redacted] of total project costs, including interest AFUDC and overhead.

The breakdown of the fixed price EPC contracts by line costs and station costs is provided in Table 1 below.

Table 1 - EPC Contract Costs

Project Element	Cost ($M)
Line*	[redacted]
Station- Hanmer	[redacted]
Station- Mississagi 230kV Ph 1	[redacted]
Station – Mississagi 500kV	[redacted]
Total	[redacted]

*The EPC contract cost for line work includes the ECI-EPC components.

The cost of EPC contracts are reflected in Tables 1 and 2 of Exhibit B, Tab 7, Schedule 1 of the Application.

Given the above, the EPC fixed price contract value represents over [redacted] of the total project cost (Lines & Stations), and nearly [redacted] of direct costs (excluding interest, overhead and contingency). When considering solely the Lines component of the project, the EPC cost represent over [redacted] of the direct costs (excluding interest, overhead and contingency). Stations were not executed under the ECI-EPC methodology and a number of long lead items such as transformers and breakers that were procured via Hydro One under existing contracts to meet the necessary timelines. Both the EPC contracts and the long lead station materials of the cost was market-tested through a competitive procurement process.

i) Please refer to part h) of this response.

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OEB STAFF INTERROGATORY - 08

Reference:
Exhibit B-7-1, Pages 2-6, Tables 1 and 2

Preamble:
Hydro One states that the NEPL cost estimate reflects current market-tested pricing obtained through the ECI-EPC procurement process and incorporates material, equipment, contractor, and contingency costs. Hydro One also notes that the estimate reflects current market conditions and risk assessments. Recent tariff measures affecting steel, aluminum, and other imported products have created uncertainty regarding future material and equipment.

Interrogatory:
a) Please identify all Project components and materials that Hydro One believes may be affected by existing or potential future tariffs.

b) For the Project costs shown in Table 1 and Table 2, please describe and quantify all categories that are currently exposed to tariff-related cost increases and list any additional risks.

c) Please explain whether the fixed-price EPC contract transfers tariff-related cost risk to the EPC contractor or whether Hydro One retains some or all of that risk.

d) Please identify any mitigation measures Hydro One has implemented or is considering to reduce exposure to tariff-related cost increases.

Response:
a) With respect to current components of the Project that are subject to tariffs, please refer to Exhibit B, Tab 7, Schedule 1, Footnote 12. Hydro One cannot reasonably opine on potential future tariffs and therefore no provision was made for any new future tariffs in the project estimate via contingency allocation.

b) Of the cost categories listed in Exhibit B, Tab 7, Schedule 1, Tables 1 and 2, the cost categories that would be directly affected by tariffs would be Materials, Equipment Rental and Contractor Costs. Unfortunately, protectionist economic policies have disruptive impacts on North American supply chains as detailed in Attachment 1 of Exhibit I, Tab 1, Schedule 3.

As described at Exhibit B, Tab 7, Schedule 1 Table 3, tariff impact is forecast to be $28.0M for Lines (i.e., Table 1 cost categories) and $4.7M for Stations as per Table 4 and 5 (i.e., Table 2 cost categories). Please refer to Attachment 1 of Exhibit I, Tab 1, Schedule 11 for quantification of these values.

c) [redacted] As the requested information relates to EPC Contract details, the response is provided in the confidential version of this response.

d) Hydro One and our partners employ a highly diversified supply chain that leverages a wide array of suppliers with production facilities both within Canada and internationally. Hydro One is working with various suppliers to source materials domestically where it is cost-prudent and feasible to reduce or eliminate any tariff risks, and has encouraged its EPCs to do the same. During the ECI phase of Project scoping and development and during the RFP competitive bid phase, enacted tariffs and the risks associated with future tariffs were a factor in the selection process. As part of the RFP phase, the EPC contractors were required to provide potential domestic alternatives, if feasible, to minimize tariff risk. When the materials cannot be sourced domestically in a cost-prudent manner, Hydro One requires the EPC to mitigate any tariff impact by attempting to source from locations subject to no, or low, tariff jurisdictions when cost prudent and feasible to do so. This strategic approach allows the sourcing of materials domestically, from North America, as well as Europe and Asia, ensuring a consistent and reliable supply of materials required to deliver the Project successfully. Diversifying sourcing locations helps mitigate the risks arising from evolving tariff conditions.

OEB STAFF INTERROGATORY - 09

Reference:

1. Exhibit B-7-1, Page 8
2. Exhibit B-7-1, Table 3, Pages 12-13

Preamble:

Hydro One states that the comparator transmission line projects presented in Reference 2 include double-circuit facilities, whereas the NEPL is a single-circuit transmission facility. To facilitate comparison, Hydro One applied a 60% adjustment factor to convert the double-circuit comparator projects to a single-circuit equivalent.

Hydro One states that the adjustment factor was derived from the California ISO 2025 Unit Cost Guides, which indicate that a 500 kV single-circuit lattice tower transmission line is approximately 58% of the cost of a comparable double-circuit transmission line on a per-length basis, and the MISO Transmission Cost Estimation Guide for MTEP24, which indicates that a 345 kV single-circuit transmission line is approximately 61% of the cost of a comparable double-circuit transmission line.

Interrogatory:

a) Please provide copies of, or references to, the specific sections, tables, and calculations within the California ISO and MISO cost guides referenced by Hydro One that support the cited 58% and 61% cost relationships.

b) Please provide the detailed calculations and methodology used to derive the 58% and 61% single-circuit-to-double-circuit cost ratios referenced in the application, including the specific tables, cost inputs, and assumptions from the California ISO and MISO documents relied upon by Hydro One. Provide all calculations in an Excel spreadsheet format.

c) Please explain how the California ISO and MISO organizations developed the cited ratios and indicate any assumptions that were made and how they apply to the NEPL.

d) Please explain why Hydro One considers the California ISO and MISO cost relationships to be applicable to the NEPL.

e) Please identify any Ontario-specific, Hydro One-specific, or Canadian transmission project data that Hydro One considered when determining the appropriate double-circuit-to-single-circuit adjustment factor. If such data was considered, please provide the results of that analysis.

f) Please explain whether the 60% adjustment factor was applied uniformly across all project cost components or whether certain costs were excluded from the adjustment. If excluded, please identify those costs and explain why.

g) Please provide the detailed calculations used to apply the 60% adjustment factor to the necessary project cost components for each of the comparable projects in Excel format.

Response:

a) Hydro One relied upon the following publicly available industry references:
   a. California ISO 2025 Unit Cost Guide;
      i. 2025 Proposed SCE Generator Interconnection Unit Cost Guide https://www.caiso.com/documents/sce-2025-per-unit-cost-guide-final.xlsx
         1. Cost Details
      ii. 2025 Horizon West Transmission Generator Interconnection Unit Cost Guide https://www.caiso.com/documents/hwt-2025-per-unit-cost-guide-final.xlsx
         1. 2025 E&C Unit Cost Details
      iii. 2025 LS Power Grid California Generator Interconnection Unit Cost Guide https://www.caiso.com/documents/lspgc-2025-per-unit-cost-guide-final.xlsx
         1. Cost Details
      iv. 2025 GridLiance West Generator Interconnection Unit Cost Guide https://www.caiso.com/documents/glw-2025-per-unit-cost-guide-final.xlsx
         1. 2025 E&C Unit Cost Details
   b. MISO Transmission Cost Estimation Guide for MTEP24: 20240501 PSC Item 04 MISO Transmission Cost Estimation Guide for MTEP24632680.pdf
      i. Table 4.1-1 and Table 4.1-2

b) Please refer to Attachment 1 of this Schedule for the requested calculations and references.

c) The CAISO unit cost guides are developed annually by participating transmission owners for generator interconnection studies using each Participating Transmission Owner's estimating practices and historical cost experience. Draft guides are reviewed through a CAISO stakeholder process and subsequently published as final cost guides. The guides provide screening-level transmission and substation unit costs and associated adjustment factors for use in interconnection planning studies.

   The MISO Transmission Cost Estimation Guide is a planning-level transmission cost estimating framework developed and maintained by the MISO for use in the MISO Transmission Expansion Plan process. The guide's methodology and cost assumptions are updated through stakeholder review and are based on MISO staff experience, vendor consultation, industry practice, and stakeholder feedback.

Transmission projects delivered within MISO and CAISO jurisdictions are subject to different regulatory, permitting, and project development requirements than those projects delivered in Ontario. However, they are generally constructed using similar transmission materials and equipment and draw upon many of the same North American and international supply chains. Furthermore, labour market conditions across Canada and the United States are influenced by many common factors affecting the availability and cost of skilled transmission construction resources.

Hydro One considers MISO and CAISO metrics to be reasonable high-level North American benchmarking references when used as directional indicators of transmission project costs, rather than direct cost comparators. Accordingly, these benchmarks provide useful context regarding the range of transmission project costs observed across North America but are not relied upon as direct predictors of the costs of Ontario transmission projects

Hydro One used the CAISO and MISO unit cost guideline values as benchmarks to normalize the adjustment to provide a high-level comparison between historical double-circuit projects and the proposed NEPL Project's single-circuit line. The 60% adjustment used was considered an appropriate and reasonable midpoint approximation, one that is supported by independent expert analysis, as completed by Charles Rivers Associates International which is included at Exhibit I, Tab 1, Schedule 3, Attachment 1 at pages 9-10.

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

f) The adjustment factor was applied uniformly across all project cost components to align with the CAISO and MISO benchmarking data.

g) Please refer to Attachment 1 of this Schedule.

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OEB STAFF INTERROGATORY - 09

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 10

Reference:
1. Exhibit B-7-1, Pages 9-10
2. Exhibit B-7-1, Table 3, Pages 12-13

Preamble:
Hydro One states that the NEPL will primarily utilize guyed lattice structures, whereas the comparator transmission line projects primarily utilized self-supporting lattice structures. Hydro One references the paper *Cost and Performance of Guyed Lattice Structures vs. Self-Supporting Towers* by Tracy and Smith and states that transmission lines utilizing guyed lattice structures experience an approximate 30% reduction in structure and foundation costs compared with a line that only uses self-supporting structures.

Hydro One further states that, based on industry standards for extra-high-voltage transmission lines and comparator project costs, this results in an estimated overall project cost reduction of approximately 16%, which was applied to the comparator projects presented in Reference 2.

Interrogatory:
a) Please provide a copy of the Tracy and Smith paper, *Cost and Performance of Guyed Lattice Structures vs. Self-Supporting Towers*, referenced by Hydro One.

b) Please explain whether the Tracy and Smith paper supports the application of a 16% adjustment to total project costs and, if not, identify the source of the methodology used to derive the 16% adjustment.

c) Please provide the detailed calculations used to apply the cost reduction to the project cost components of the comparable projects in Excel format.

d) Please identify the percentage of total transmission line project costs that Hydro One assumed were attributable to structures and foundations when deriving the 16% adjustment.

Response:
a) The Tracy & Smith Paper is only available to paying subscribers of the American Society of Civil Engineers ("ASCE") Library. Hydro One is not authorized to provide copies of licensed material from the ASCE Library and is only permitted to use brief

quotations from the materials[1], as Hydro One did at Exhibit B, Tab 7, Schedule 1, page 9. An abstract of the paper is publicly available on the ASCE Library website.[2]

b) The Tracy & Smith Paper does not directly prescribe a 16% reduction to total project costs. Rather, it indicates that structure and foundation costs for guyed lattice designs may be approximately 30% lower than comparable self-supporting tower designs.

As referenced on page 10 of Exhibit B, Tab 7, Schedule 1, the NEPL Project's design parameters were developed in accordance with accepted industry sources - EPRI Red Book and CIGRÉ Greenbook.

The EPRI Red Book and the CIGRÉ Greenbook set out structures and foundation costs for transmission lines above 300 kV as percentage of total costs. Based on those standards, a representative mid-point value of 55% was selected to represent the structures and foundation costs for transmission lines.

The 30% reduction in structure and foundation costs for guyed lattice designs was multiplied by the 55% factor describing the expected structure foundation percentage of total costs to develop the 16% adjustment (30% x 55% = 16%). Therefore, the 16% adjustment was developed by Hydro One using the findings of the Tracy & Smith Paper together with industry-standard transmission line cost breakdowns and comparator project cost data.

c) Please refer to Attachment 1 of this Schedule.

d) Please refer to the response in b) of this Schedule.

[1] ASCE Library Permitted Use https://ascelibrary.org/page/termsofuse
[2] https://ascelibrary.org/doi/10.1061/9780784484463.006

STRUCTURE ADJUSTMENT SPREADSHEET

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 11

Reference:
Exhibit B-7-1, Tables 3-5, Pages 12-19

Preamble:
At Reference 1, Hydro One provides an analysis of costs on comparable projects for both line and station work for the Project.

Interrogatory:

a) Table 3 contains an adjustment labelled "Newly Enacted Tariff Adjustment" and Table 4 and Table 5 contain an adjustment labelled "Tariff Adjustment".
   a. Please clarify what these adjustments represent.
   b. Is there a difference between "Newly Enacted Tariff Adjustment" and "Tariff Adjustment"?
   c. How were the "Newly Enacted Tariff Adjustment" and "Tariff Adjustment" values calculated and what factors contributed to this analysis?
   d. Provide an Excel spreadsheet showing how the adjustments were calculated, the factors that were included, and what values were assigned to each factor.

b) For Table 3, Table 4 and Table 5, Hydro One noted that the inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.
   a. Please confirm if Hydro One has applied the OEB's 2027 inflation parameters in the escalation adjustment.
   b. If not, please update the escalation adjustment calculations for Table 3, Table 4, and Table 5 using the OEB's 2027 inflation parameters.

c) For Table 3, Table 4 and Table 5, please provide detailed calculations (in Excel format) for the Escalation Adjustment values (or the Total Adjusted Comparable Cost) for the three comparable projects. The calculations should show the annual inflation parameters applied for each year.

d) In Table 4, the "Total Adjusted Comparable Cost" of the Hanmer TS is shown to be $64.8 million. This is higher than all comparable projects. Please discuss why the station work at Hanmer TS has a higher estimated adjusted cost compared to the comparable projects.

e) In Table 5, the "Total Adjusted Comparable Cost" of the Mississagi TS is shown to be $226.9 million. This is significantly higher than all comparable projects. Please discuss why the station work at Mississagi TS has a higher estimated adjusted cost compared to the comparable projects.

Response:

a)

a. As described in Exhibit B, Tab 7, Schedule 1, the Newly Enacted Tariff Adjustment accounts for incremental costs associated with new tariffs effective December 26, 2025, insofar as the Government of Canada having imposed a 25% tariff on imported steel derivative products, including tower steel structures, conductors and tower foundation steel materials.[1] These costs are attributed to current government policy and were not incurred by the other comparable projects. By contrast, the NEPL Project is subject to the current tariff policy which imposes a 25% tariff on imported steel derivative products and therefore as such an adjustment to the NEPL Project cost is necessary.

b. Rather than repeating "*Newly Enacted Tariff Adjustment*", the descriptive wording in the subsequent tables was abbreviated to simply, "*Tariff Adjustment*". There is no intentional difference between the terminology used, and both are intended to capture the government's newly enacted tariff policy on imported steel products, among other things. The distinction between Table 3 and Tables 4 and Table 5 is that the former is related to the transmission line component of the Project and the latter are related to the station component of the Project.

c. The adjustment reflects the combined effect of: (i) the tariffs in effect at the time the estimate was developed, as detailed in subpart (a) above, and (ii) the forecast costs associated with the components subject to those tariffs. The adjustment amount is determined by multiplying the applicable tariff rates by the forecast costs of the affected components.

d. Please refer to Attachment 1. Attachment 1 has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

b) The OEB 2027 Inflation Parameters referenced by OEB Staff were issued on June 11, 2026.[2] This leave to construct application, including all supporting evidence, was filed on May 19, 2026.

a. Given that the leave to construct application predates the issuance of the OEB 2027 Inflation Parameters, Hydro One did not apply the OEB's 2027 Inflation Parameters in the escalation adjustment.

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[1] https://www.canada.ca/en/department-finance/news/2025/12/list-of-steel-derivative-products-subject-to-25-per-cent-tariffs-effective-december-26-2025.html

[2] https://www.rds.oeb.ca/CMWebDrawer/Record/944591/File/document

b. Please refer to Attachment 2 for the escalation adjustment using the OEB's 2027 Inflation Parameters.

c) Please refer to Attachment 3.

d) In concert with cost escalation pressures since the delivery of the comparator projects as described in Exhibit I, Tab 1, Schedule 3, the main driver for the delta is predicated on the cost escalation factor utilized to escalate the adjusted base cost to a comparable 2029 cost forecast. As detailed in sub-part c of this interrogatory, to escalate historical costs in this application Hydro One has utilized a conservative escalation, notably the OEB inflation factor as most recently updated.[3] However, recent OEB-approved rebasing applications have all exceeded these defined inflationary increases. Consequently, OEB inflationary levels may not realistically reflect actual market costs and therefore fail to appropriately escalate historical capital costs for current industry capital cost pressures for comparison purposes.

As a reasonable escalation alternative to provide the OEB assurance that the forecast cost remains in-line with previously completed works, Hydro One has utilized the OEB's approved Uniform Transmission Revenue Requirement ("UTRR") at the time of each compared project and escalated the adjusted comparable project cost by the compound annual growth rate of the OEB's approved UTRR to today's date. That compound annual growth rate is then held constant until the forecast in-service date. As shown in Figures 1 through 3, below, once this more appropriate escalation is implemented the Hanmer TS work at an adjusted cost of $64.8M is in-line with the least expensive comparator (Bruce A TS /Bruce B SS) and significantly lower than the estimated adjusted costs of the comparable projects detailed in Exhibit B, Tab 7, Schedule 1.

Figure 1 - Bruce A TS /Bruce B SS	
2012 OEB Approved Uniform Transmission Revenue Requirement[4]	$1,430,767,113
2026 OEB Approved Uniform Transmission Revenue Requirement[5]	$2,389,605,744
Compound Annual Growth Rate of UTRR	**3.73%**
Comparable Cost Before Escalation at B-7-1 in 2012 ($M)	$34.20
Inflationary Increase $(M)	$28.33
Total Adjusted Cost in 2029 ($M)	**$62.53**

[3] https://www.rds.oeb.ca/CMWebDrawer/Record/901406/File/document
[4] EB-2011- 0268 – OEB Decision & Order – Appendix A – Issued December 20, 2011
[5] EB-2025-0232 – OEB Decision & Order – Schedule A – Issued January 15, 2026

Figure 2 - Evergreen SS	
2014 OEB Approved Uniform Transmission Revenue Requirement[6]	$1,494,684,771
2026 OEB Approved Uniform Transmission Revenue Requirement	$2,389,605,744
Compound Annual Growth Rate of UTRR	**3.99%**
Comparable Cost Before Escalation at B-7-1 in 2014 ($M)	$39.12
Inflationary Increase $(M)	$29.89
Total Adjusted Cost in 2029 ($M)	**$69.01**

Figure 3 - Ashfield SS	
2015 OEB Approved Uniform Transmission Revenue Requirement[7]	$1,568,818,721
2026 OEB Approved Uniform Transmission Revenue Requirement	$2,389,605,744
Compound Annual Growth Rate of UTRR	**3.90%**
Comparable Cost Before Escalation at B-7-1 in 2015 ($M)	$38.51
Inflationary Increase $(M)	$35.05
Total Adjusted Cost in 2029 ($M)	**$73.56**

e) Similar to the approach outlined in part d, above, if a less conservative escalation factor is applied to the comparator projects, the Mississagi TS cost of $226.9M is materially less than the other greenfield comparable station project provided (Clarington TS). This is detailed in Figure 4.

Figure 4 - Clarington TS	
2018 OEB Approved Uniform Transmission Revenue Requirement[8]	$1,603,249,975
2026 OEB Approved Uniform Transmission Revenue Requirement	$2,389,605,744
Compound Annual Growth Rate of UTRR	**5.12%**
Comparable Cost Before Escalation at B-7-1 in 2018 ($M)	**$131.67**
Inflationary Increase $(M)	**$105.14**
Total Adjusted Cost in 2029 ($M)	**$236.81**

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[6] EB-2012-0031 – OEB Decision & Order – Exhibit 4.0 – Issued January 9, 2014
[7] EB-2014-0357 – OEB Decision & Order – Appendix A – Issued January 8, 2015
[8] EB-2017-0359 – OEB Decision & Order – Appendix A – Issued February 1, 2018

TARRIF ADJUSTMENT CALCULATIONS

This attachment has been filed separately in MS Excel format. Confidential treatment of this attachment has been requested separately.

2027 OEB INFLATION ADJUSTMENT

This attachment has been filed separately in MS Excel format.

2026 OEB INFLATION ADJUSTMENT

This attachment has been filed separately in MS Excel format.

OEB STAFF INTERROGATORY - 12

Reference:
Exhibit E-1-1, Pages 1-2

Preamble:
Hydro One states that to complete the Project's station scopes of work, Hydro One is required to acquire land rights from one directly impacted private landowner for construction of the proposed new 500 kV Mississagi TS facilities. Hydro One further stated that it is working with the landowner to negotiate a voluntary agreement.

Interrogatory:

a) Please provide an update on the negotiations with the landowner for the necessary rights required for the construction of the proposed new 500 kV Mississagi TS facilities.

b) Should Hydro One not successfully negotiate a voluntary agreement with the landowner, how does Hydro One propose to obtain the necessary land rights?

c) Please discuss whether a delay in obtaining the required land rights could affect the construction schedule, critical milestones, or the planned December 2029 in-service date.

d) Please provide a map showing where Hydro One's current rights end and where Hydro One is seeking additional land rights for the construction of the proposed 500 kV Mississagi TS facilities.

Response:

a) At the time of filing these responses, negotiations with the landowner for the necessary rights required for the construction have been progressing well. Provided that negotiations continue to progress as expected, Hydro One anticipates that a voluntary settlement will be reached before the end of 2026.

b) In the event a voluntary settlement cannot be reached, Hydro One intends to file for expropriation under s.99 of the OEB Act.

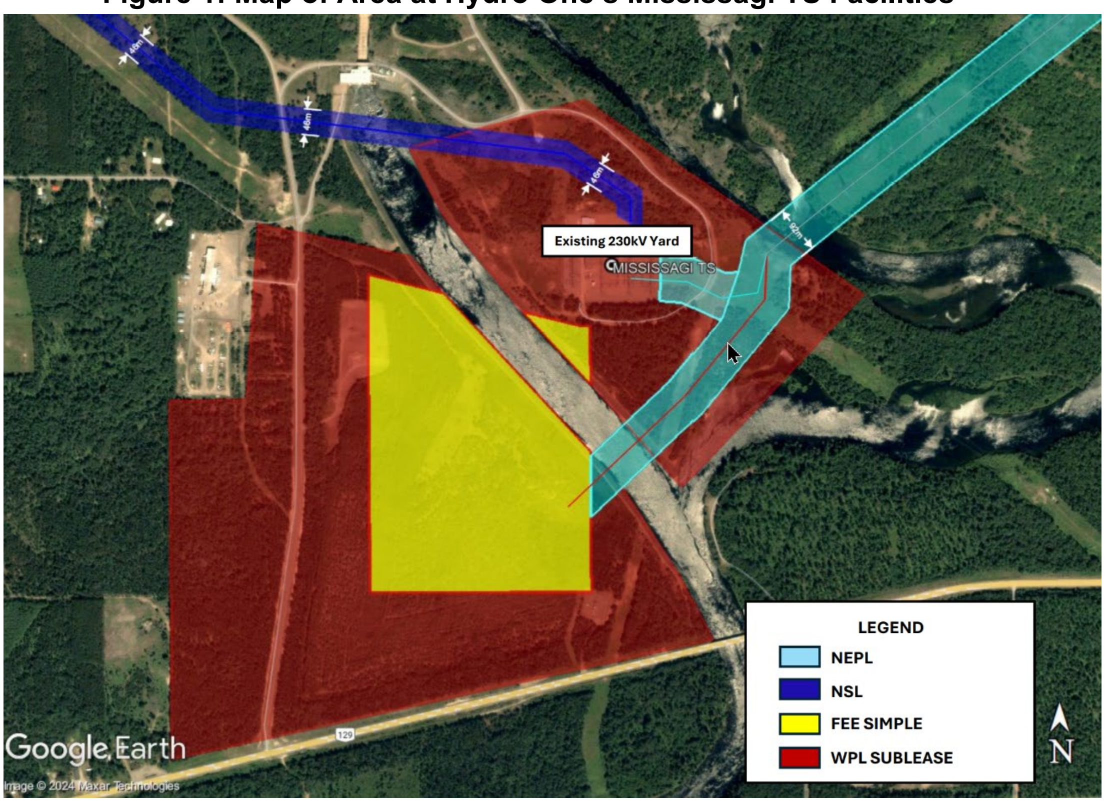
c) As outlined above, Hydro One anticipates the land rights will be in place by year end. The landowner has agreed to enter into a temporary construction license that would allow Hydro One to start Project construction should there be any delays in finalizing the agreements, thereby avoiding any delays to construction start or the Project delivery in-service date.

d) Please refer to Figure 1 of this Schedule for a map illustrating the area in the vicinity of Hydro One's Mississagi TS facilities. Figure 1 shows where Hydro One is seeking additional land rights for the construction of the proposed 500 kV facilities at Mississagi TS.

As shown by the map, Hydro One intends to purchase the land shaded yellow at PIN 314100056 that is identified in Exhibit E, Tab 1, Schedule 1, Attachment 1, page 1, of the Application. Additionally, Hydro One plans to enter into a sublease agreement for the lands shaded in red on the map which will accommodate land requirements for the proposed transmission line and station works.

Hydro One and the landowner have confirmed with the Ministry of Natural Resources and Forestry ("MNRF") that the existing lease permits the proposed station expansion and also permits the landowner to sublease the required lands to Hydro One. Accordingly, Hydro One will negotiate the terms of the sublease directly with the landowner, and that MNRF will not be required to grant Hydro One any additional land rights to deliver the Project.

Figure 1: Map of Area at Hydro One's Mississagi TS Facilities



OEB STAFF INTERROGATORY - 13

Reference:

Exhibit F-1-1, Page 1

Preamble:

At Reference 1, Hydro One states that IESO will provide a Registration Approval Notification confirming that the facility is fully authorized to connect to the IESO-controlled grid.

Interrogatory:

a) Please provide an update on Hydro One receiving the Registration Approval Notification from the IESO. If it has not yet been received, when does Hydro One anticipate receiving it?

Response:

a) Please refer to Appendix A of Exhibit F, Tab 1, Schedule 1, Attachment 1 for the IESO's General Requirements for connection, e.g., on-site commissioning tests post-construction. Hydro One expects to receive the Registration Approval Notification in Q3 2029, to allow for a December 2029 in-servicing of the required facilities consistent with the Project Schedule defined at Exhibit B, Tab 11, Schedule 1.

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OEB STAFF INTERROGATORY - 14

Reference:

1. OEB CEO Policy 2026-01
2. Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025) (IEP)

Preamble:

Reference 1 requires identification of "the portions of the *Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025)* that are relevant to the matters in issue in the proceeding."

Interrogatory:

a) Please discuss if there are portions of the *Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025)* that Hydro One considers relevant to this application.

Response:

a) Further to Hydro One's response to Exhibit I, Tab 1, Schedule 5, part c), the NEPL Project is identified in the Integrated Energy Plan as a key project necessary to unlock opportunities in Northern Ontario and an example of Indigenous economic participation in transmission projects[1].

The NEPL Project has also been identified as a priority transmission project in the Order in Council issued October 19, 2023 by the Lieutenant Governor in Council ("OIC") as found at Exhibit B, Tab 3, Schedule 1, Attachment 2. As described therein, the Province of Ontario considers it critical to expand Ontario's transmission system to provide a reliable and adequate supply of electricity to support economic growth and electrification initiatives throughout Northeastern and Eastern Ontario. Accordingly, the OEB's Procedural Order excludes need and alternatives from the issues because the OIC designates the Project as a priority.

As included in the *Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025)*, the portions that Hydro One considers relevant to the facts of this case are set out below, however as ascribed to above, are not required to support the need for the Project given it 'priority' status as already established by the Provincial government and accepted by the OEB.

[1] mem-energy-for-generations-en-2025-07-18.pdf – pp. 73 and 135.

Relevant Excerpts in the IEP referencing the NEPL Project

Chapter 3

Northern Ontario holds immense potential for new clean electricity generation, economic development, job creation, Indigenous partnerships and equity ownership to advance action on reconciliation. That potential can only be realized if transmission infrastructure is in place to move electricity where it is needed.

Since 2023, guided by the recommendation from the IESO and consultation with Indigenous communities, the government has taken significant steps to support the expansion of transmission infrastructure across northern Ontario. These projects will increase transfer capacity across the North, open the door to new generation, and support the region's growing industrial base, including the electrification of steel making at Algoma Steel in Sault Ste. Marie. Key projects already underway include:

- *Wawa to Porcupine Transmission Line: A new 230 kV line that is being built to 500 kV standards, between Wawa Transformer Station (south of Wawa) and Porcupine Transformer Station (Timmins), expected to be in-service by 2030.*
- *North Shore Link Project: A new 230 kV line between Mississagi Transformer Station (Sault Ste. Marie) and Third Line Transformer Station (west of Sudbury), expected to be in-service by 2029.*
- ***Northeast Power Line: A new 500 kV transmission line between Mississagi Transformer Station (west of Sudbury) and Hanmer Transformer Station (greater Sudbury area), expected to be in-service by 2029.*** [emphasis added]

Together, these projects will add up to 900 MW of new electricity transfer capacity – a major step forward in unlocking new generation, supporting industrial growth, and increasing regional reliability.

Chapter 8

…advancing economic reconciliation is essential to Ontario's energy future. As the province plans for growing demand and builds out new infrastructure, Indigenous communities are not only key partners in this work, they are leaders in shaping Ontario's energy transformation. Through equity partnerships, energy planning, and project development, Indigenous communities are helping deliver the generation, transmission, and innovation Ontario needs — while unlocking long-term economic opportunities that build intergenerational prosperity. Ensuring Indigenous communities share in the economic benefits of energy development is at the heart of the province's approach…

In 2022, Hydro One established a 50-50 First Nation Equity Partnership Model for new, large scale transmission projects. For transmission projects valued at over $100 million, Hydro One offers First Nations the opportunity to invest in up to 50 per cent ownership of the line…

The equity participation model will be applied to several new major transmission projects being developed by Hydro One, including the Northeast Power Line…

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