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**BY EMAIL**

April 22, 2026

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Dear Ritchie Murray:

**Re: Ontario Energy Board (OEB) Staff Submission  
Hydro One Networks Inc. (Hydro One)  
Leave to Construct and Expropriation Application – Welland-Thorold  
Project  
OEB File Number: EB-2025-0290**

Please find attached OEB staff's submission in the above referenced proceeding, pursuant to Procedural Order No. 3.

Yours truly,

Muhammad Yunus  
Advisor, Transmission

Encl.

cc: All parties in EB-2025-0290



# **ONTARIO ENERGY BOARD**

## **OEB Staff Submission**

**Hydro One Networks Inc.**

**Leave to Construct and Expropriation Application – Welland-Thorold Project**

**EB-2025-0290**

**April 22, 2026**

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## 1. Background and Overview

### 1.1 Overview of the Application

On November 18, 2025, Hydro One Networks Inc. (Hydro One) applied to the Ontario Energy Board (OEB) under section 92 of the *Ontario Energy Board Act, 1998* (OEB Act) for an order granting leave to construct approximately 18.5 kilometres of electricity transmission line and associated facilities between Abitibi Consolidated Junction and Crowland Transformer Station in the Niagara area (Welland-Thorold Project or the Project). Hydro One has also applied to the OEB, pursuant to section 97 of the OEB Act, for approval of the form of land-use agreements offered, or to be offered, to affected landowners.

Hydro One further stated in the application that if leave to construct is granted, it is also requesting relief under section 99(1) of the OEB Act for an order granting authority to expropriate certain interest in lands.

In Procedural Order No. 2, dated March 5, 2026, the OEB decided to bifurcate the proceeding into two phases. Phase 1 will address the leave to construct relief. Phase 2, the expropriation part of this application, will be placed into abeyance, and will proceed if the OEB grants Hydro One leave to construct relief in Phase 1. This OEB staff submission pertains to the scope of Phase 1 of this proceeding.

### 1.2 Overview of OEB Staff Submission

OEB staff generally supports Hydro One's section 92 request for leave to construct, subject to the standard conditions of approval set out in section 2.7 of this submission.

OEB staff supports Hydro One's section 97 request for approval of the forms of agreements it will offer to affected landowners.

OEB staff's submission is provided in detail in the following sections.

## 2. OEB Staff Submission

### 2.1 Project Need & Project Alternatives

#### 2.1.1 Project Need

The application states that the Project is needed to increase supply capacity to support continued load growth and improve reliability in the Niagara area.<sup>1</sup> To support the need for the Project, Hydro One references:

- The IESO's 2022 Niagara Integrated Regional Resource Plan (IRRP)<sup>2</sup>
- The Niagara Technical Working Group's 2023 Niagara Regional Infrastructure Plan (RIP)<sup>3</sup>
- The IESO's Supplemental Evidence to Support the Need for the Welland Thorold Power Line Project (IESO Supplemental Evidence)<sup>4</sup>

The IRRP recommended the Project to manage overloads during outage conditions and to enable load growth. The RIP recommended the Project as part of the near and mid-term planning horizon for 2023-2032.

The IESO Supplemental Evidence updated the load forecast from the IRRP, stating that the Project is required to meet the previously unanticipated 500 MW of load growth, relative to the IRRP forecasts, that the Niagara region is expected to experience. This increased demand relative to the 2022 forecast has raised concerns regarding how to maintain reliability in the near term.

The Project is intended to address supply capacity concerns on the Niagara Region 115 kV system in the event that three of the four transformers at Allanburg Transformer Station (TS) are out of service. Additionally, the Project will address overloading and load security concerns on the A6C and A7C circuits and address capacity and asset renewal needs at the Crowland TS.<sup>5</sup>

The application states that the Project is a non-discretionary project as it is being undertaken in accordance with direction from the IESO in the regional planning process to address forecasted load growth.<sup>6</sup>

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<sup>1</sup> Exhibit B, Tab 3, Schedule 1

<sup>2</sup> Exhibit H, Tab 1, Schedule 1, Attachment 2

<sup>3</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1

<sup>4</sup> Exhibit B, Tab 3, Schedule 1, Attachment 1

<sup>5</sup> Exhibit B, Tab 3, Schedule 1

<sup>6</sup> Exhibit B, Tab 4, Schedule 1

Based on recommendations from the IRRP, the Project is designed to provide up to 180 MW of incremental transmission capacity and consists of the construction of approximately 18.5 km of new transmission line. Hydro One will convert the Crowland TS from a 115 kV supply to a 230 kV supply to connect to the new 230 kV system and alleviate loading on the existing 115 kV system.<sup>7</sup>

Twenty-year station load forecast information was included in the RIP, and Table 1 shows a five-year period from 2028-2032. In its interrogatory responses, Hydro One provided five-year historical demand information for stations supplied by Hydro One in the Niagara area, shown in Table 2. The information in Tables 1 and 2 shows that the Niagara region has experienced steady load growth in the past and that this is expected to continue in the coming years.

**Table 1: Niagara Region Station Load Forecast<sup>8</sup>**

Station	2028	2029	2030	2031	2032
AllanburgTS	46	46	46	46	47
BeamsvilleTS	83	84	85	86	86
BuntingTS	61	62	64	65	66
CarltonTS	95	96	97	99	100
CNPIStation#17MTS	26	26	26	26	26
CNPIStation#18MTS	35	35	35	35	35
CrowlandTS	116	118	120	121	121
DunnvilleTS	38	38	38	39	39
GlendaleTS(T1/T2)	33	34	35	35	36
GlendaleTS(T3/T4)	7	7	7	8	8
KalarMTS	66	67	69	69	69
MurrayTS(T11/T12)	78	78	79	79	79
MurrayTS(T13/T14)	43	43	44	44	44
NiagaraWestMTS	60	62	63	65	66
NOTL#2MTS	40	40	41	42	43
NOTLYorkMTS	22	22	23	23	24
PortColborneTS	36	36	37	37	37
StanleyTS	64	64	65	65	66
ThoroldTS	25	26	26	26	26
VansickleTS	55	56	57	58	59
VinelandDS	23	23	24	25	25

<sup>7</sup> Exhibit B, Tab 2, Schedule 1

<sup>8</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, Appendix C

**Table 2: Five-Year Historic Demand in the Niagara Region<sup>9</sup>**

Year	2021	2022	2023	2024	2025
Peak Demand (MW)	964	909	956	949	1026

### 2.1.2 Project Alternatives

The applicant filed evidence demonstrating that non-wires and wires alternatives to address the need were assessed, and that the Project is the preferred alternative.

The RIP provided multiple alternatives to supply the forecast demand growth at Crowland TS. These included an option to maintain the status quo and two sets of transmission options. The alternative to maintain the status quo was rejected by the RIP as it would prevent load growth in the Niagara region.<sup>10</sup>

Option Set 1 involved the continued buildout of the 115 kV system and included the following:

- 1) Rebuilding the 115 kV Crowland TS like-for-like
- 2) Adding a second 115 kV station in Welland, supplied by the A6C/A7C circuits
- 3) Adding a new 230 kV switchyard at Allanburg TS

Option Set 2 involved expanding the 230 kV system and included the following:

- 1) Replacing the 115 kV Crowland TS with a new 230 kV station
- 2) Building a new double-circuit 230 kV transmission line from the Q24HM/Q29HM circuits to the new 230 kV Crowland TS

Option Set 1 was estimated to cost between \$253 million to \$353 million, while Option Set 2 was estimated to cost \$128 million.

Non-wires options that incorporated conservation, demand management, battery storage, and generation were also assessed as part of the IRRP. While the non-wires options could address the expanded capacity needs for Crowland TS, they were not considered a feasible solution to solve load security needs and were ruled out. Option Set 2 was recommended in the RIP as the more cost-effective solution.<sup>11</sup>

In the RIP, the estimated costs of the components of the two option sets were broken out as shown in Table 3 below.

<sup>9</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 5, part a

<sup>10</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, pp. 35-36

<sup>11</sup> *Ibid.*

**Table 3: Cost Components of Options for Project Alternatives**

Option Set 1	
Rebuild the 115 kV Crowland TS like-for-like and add a second 115 kV station	\$78 million <sup>12</sup>
Uprate A6C/A7C circuits to accommodate new 115 kV station	\$23 million <sup>13</sup>
Add a new 230 kV switchyard at Allanburg TS	\$253 million <sup>14</sup>
<b>Total Cost</b>	<b>\$354 million</b>
Option Set 2	
Construct new 230 kV transformer station to replace 115 kV Crowland TS and build 18 km double circuit 230 kV line to connect new station to Q24HM/Q29HM 230 kV circuits	\$128 million <sup>15</sup>
<b>Total Cost</b>	<b>\$128 million</b>

Based on the estimated costs in the RIP, Option Set 2 remained the recommended alternative and was further developed into the Project. In its application, Hydro One has submitted that the total project costs are now estimated to be \$311.4 million instead of the \$128 million figure contained in the RIP and IRRP.

**Table 4: NPV Sensitivity Analysis of Alternatives**

	Alternative #1 (1192.5 kcmil ACSR)	Alternative #2 (1443.7 kcmil ACSR)	Alternative #3 (1433.6 kcmil ACSS)
Total Cost (\$M)	232.5	233.4	234.9
Annual Losses (MWh)	15,880.30	13,104.01	12,655.21
Losses at System Peak (MW)	2.472	2.040	1.970
Assumptions	Net Present Value		
Energy Price: \$53.16/MWh <b>Capacity Price: \$164,052/MW</b>	-\$229.15M	<b>-\$224.69M</b>	-\$225.13M
Energy Price: \$120/MWh <b>Capacity Price: \$164,052/MW</b>	-\$254.54M	-\$245.65M	<b>-\$245.37M</b>

Hydro One stated that it performed a line-loss analysis with three different conductor sizes. The 50-year Net Present Value (NPV) analysis used a 5.65% discount rate and a sensitivity analysis used varying values for the price of energy. In response to an interrogatory, Hydro One provided the information in Table 4, which summarizes the results of its NPV sensitivity analysis.<sup>16</sup> Hydro One selected Alternative 3, the 1433.6 kcmil ACSS conductor as it represented the most cost-efficient alternative when accounting for line losses.

<sup>12</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, p. 35

<sup>13</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, p. 31

<sup>14</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, p. 32 and 35

<sup>15</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, pp. 34-36

<sup>16</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 7

### 2.1.3 Proposed Route

Hydro One filed an overview map of the Project which represents the final preferred route and station locations that were selected through the Class Environmental Assessment (EA) process.<sup>17</sup>

The project route was separated into three segments and the EA compared and evaluated multiple route alternatives for each segment. The route alternatives were evaluated against criteria related to the natural environment, socio-economic environment, Indigenous culture, values and land use, and technical and cost considerations. The EA established the preferred route based on the overall performance against these criteria.<sup>18</sup> Through interrogatories, Hydro One provided the final Environmental Study Report for the OEB to review.<sup>19</sup>

Hydro One stated that the preferred route, as outlined in the EA, utilizes existing transmission corridors for approximately 70% of its total length. Hydro One stated that this route minimizes the natural and socioeconomic environmental impacts.<sup>20</sup>

Through interrogatories Futecan, a land owner and intervenor in the proceeding, requested an update from Hydro One as to whether Hydro One had reconsidered route options related to Futecan's property and how the preferred route identified in the EA affected it. In response, Hydro One stated that after considering Futecan's feedback in routing workshop discussions and through technical review, it had updated the route to reflect preferences and impact mitigation concerns raised by Futecan.<sup>21</sup>

### Submission

OEB staff submits that the evidence demonstrates the need for the Project to increase transmission supply capacity to meet the increasing power demands in the Niagara region and to improve system reliability to manage future load growth.

OEB staff agrees that the Project is consistent with the recommendations contained in the IRRP and the RIP.

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<sup>17</sup> Exhibit B, Tab 2, Schedule 1, Attachment 1

<sup>18</sup> Welland Thorold Power Line Class Environmental Assessment: Final Environmental Study Report, November 21, 2025

<sup>19</sup> [Welland Thorold Power Line Class Environmental Assessment: Final Environmental Study Report](#), November 21, 2025

<sup>20</sup> Exhibit B, Tab 6, Schedule 1

<sup>21</sup> Interrogatory Responses, Exhibit I, Tab 2, Schedule 1

OEB staff notes that the cost of the Project has grown substantially from \$128 million estimated in 2023<sup>22</sup> to \$311.4 million quoted in this application<sup>23</sup>, and Hydro One has not provided any justification for this. However, this updated cost is still less than the \$354 million cost of the alternative wires option set that was contained in the RIP.

OEB staff notes that the line-loss analysis that was provided in response to an interrogatory contains inconsistent results. The analysis shows that the proposed 1433.6 kcmil ACSS conductor (Alternative 3) has the lowest NPV cost when the energy price is \$120/MWh. However, the sensitivity analysis shows that a different conductor, 1443.7 kcmil ACSR (Alternative 2), has the lowest NPV cost at an energy price of \$53.16/MWh.<sup>24</sup>

OEB staff notes Hydro One did not provide an explanation for using the \$120/MWh energy price and did not explain why this price was used to determine the preferred conductor alternative. However, OEB staff recognizes that the difference in NPV at the lower energy price is \$440,000 in favour of Alternative 2, and \$280,000 in favour of Alternative 3, the selected alternative, at the higher energy price. In light of the total project cost, OEB staff notes that this cost difference is largely immaterial and as such, OEB staff does not take issue with selecting the alternative that minimizes line losses, as Hydro One has done.

OEB staff submits that the map that Hydro One filed with the application satisfies the requirements of the Act<sup>25</sup> and issue 7.1 of the standard issues list<sup>26</sup> for leave to construct applications.

OEB staff has no concerns with the proposed route for the Project as established through the EA process and the adjustments made to accommodate Futecan's concerns. OEB staff notes that the assessment of the route as part of the EA is comprehensive, evaluating various criteria related to the natural environment, socio-economic environment, Indigenous culture, values and land use, and technical and cost considerations. OEB staff recognizes that it appears based on Hydro One's interrogatory responses that work was done between Hydro One and Futecan to find an acceptable solution to both parties.

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<sup>22</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, page 32

<sup>23</sup> Exhibit B, Tab 7, Schedule 1, page 1

<sup>24</sup> \$53.16/MWh represents the simple average Ontario Electricity Market Price for the period November 1, 2025, to October 31, 2026, as shown in the [Regulated Price Plan: Price Report](#), published on October 17, 2025

<sup>25</sup> Section 94 of the Act requires the applicant to file "a map showing the general location of the proposed work and the municipalities, highways, railways, utility lines and navigable waters through, under, over, upon or across which the proposed work is to pass."

<sup>26</sup> [OEB Standard Issues List for Leave to Construct Applications](#)

## 2.2 Project Cost

The estimated total capital cost of the Project is \$311.4 million, which consists of \$234.9 million for line work and \$76.5 million for station work. An additional \$3.4 million of OM&A removal costs are associated with the construction of the project, bringing the total cost of the project to \$314.8 million.

Hydro One has indicated that this cost estimate is based on a fixed-price Engineering, Procurement and Construction (EPC) contract and carries a confidence level consistent with a Class 3 (-20% / +30%) estimate classification under the Association for the Advancement of Cost Engineering (AACE) International system, reflecting a moderate level of definition for project scope, risk, and cost estimation.

### Line Costs

The estimated cost for the line work is \$234.9 million, covering the construction of approximately 18.5 km of new transmission line. This includes 10.5 km of new 230 kV transmission line and 8 km of new triple circuit transmission line (two 230 kV circuits and a single 115 kV circuit).

Hydro One has drawn comparisons to similar projects, such as the Guelph Area Transmission Refurbishment Project, the Power South Nepean Project and the Woodstock Area Transmission Reinforcement Project, all of which involved constructing 230 kV transmission lines in either southwestern or eastern Ontario.<sup>27</sup> To adjust the costs, OEB-inflation parameters were used for 2022-2026, with the 2026 rate of 3.5% being held steady for periods after 2026. A fixed rate of 2% was used for years before 2022.<sup>28</sup>

As shown below, the Project's line work costs are estimated at approximately \$4.8 million per kilometre, which is higher than the comparable projects such as the Power South Nepean Line Project (\$4.4 million/km) and the Woodstock Area reinforcement (\$3.6 million/km), and lower than the Guelph Area Transmission Refurbishment Project (\$6.5 million/km).<sup>29</sup> Hydro One stated that adjustments were made to the Project's costs to account for unique issues affecting the Project, such as specific costs related to the design of the structures and circuits to account for route-specific concerns.<sup>30</sup>

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<sup>27</sup> Exhibit B, Tab 7, Schedule 1

<sup>28</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 13, parts d and e

<sup>29</sup> EB-2019-0077, Decision and Order, October 17, 2019; EB-2007-0027, Decision and Order, October 11, 2007; EB-2013-0053, Decision and Order, September 26, 2013

<sup>30</sup> Exhibit B, Tab 7, Schedule 1

**Table 5: Costs of Comparable Line Projects<sup>31</sup>**

	<b>Guelph Area Transmission Refurbishment Project</b>	<b>Power South Nepean Project</b>	<b>Woodstock Area Reinforcement</b>	<b>Welland Thorold Power Line (The Project)</b>
Total Adjusted Comparable Cost (\$000s)	\$32,248	\$54,051	\$49,294	\$88,510
Approximate Length (km)	5.0	12.2	13.6	18.5
Unit Cost (\$000s/Km)	<b>\$6,450</b>	<b>\$4,430</b>	<b>\$3,625</b>	<b>\$4,784</b>

A breakdown of the Project line costs is shown below:

**Table 6: Line Costs<sup>32</sup>**

	<b>Estimated Cost (\$000's)</b>	<b>Percentage (%)</b>
Materials	\$25,500	11%
Labour	\$14,000	6%
Equipment Rental & Contractor Costs	\$99,300	42%
Sundry	\$2,100	1%
Contingencies	\$33,200	14%
Overhead	\$4,300	2%
Allowance for Funds Used During Construction	\$16,200	7%
Real Estate	\$40,300	17%
<b>Total Line Work</b>	<b>\$234,900</b>	<b>100%</b>

### Station Costs

The estimated cost for the station work to convert Crowland TS from a 115 kV supply to a 230 kV supply is \$76.5 million. This includes the installation of two new 230/27.6 kV transformers with associated equipment. Additional modifications and additions to protection and control, SCADA, metering, and AC/DC station service are required. The Project will also require modifications to telecommunications facilities at Sir Adam Beck TS, Beach TS and Middleport TS.

Hydro One explained that unlike line work, direct per-kilometer cost comparisons for station work are not always feasible due to unique site conditions and station configurations, which make individual station cost comparisons challenging. However, Hydro One submitted that the selected comparable projects are considered reasonable because they all include the replacement of an existing operational DESN.<sup>33</sup> Inflation rates to adjust costs and compare projects were calculated similarly to how line cost

<sup>31</sup> Exhibit B, Tab 7, Schedule 1, Table 5, p. 9

<sup>32</sup> Exhibit B, Tab 7, Schedule 1, Table 1, p. 1

<sup>33</sup> Exhibit B, Tab 7, Schedule 1

comparisons were determined.<sup>34</sup>

The comparable station cost for the Project at Crowland TS is estimated at \$51.9 million, within range of comparable projects such as St. Isidore TS at \$47.3 million, Minden TS at \$52 million and Arnprior TS at 43.2 million. Hydro One stated that adjustments were made to the Project's costs to account for unique issues affecting the Project, such as geotechnical conditions and project-specific design choices.<sup>35</sup> Through interrogatories, Hydro One noted that the higher costs associated with Crowland TS are attributed to the higher maximum transformer capacity the station will have. This higher capacity affects the size and cost of transformers but also the station infrastructure required to support it.<sup>36</sup>

**Table 7: Costs of Comparable Station Projects (Crowland TS)<sup>37</sup>**

	St. Isidore TS	Minden TS	Arnprior TS	Crowland TS (The Project)
Total Adjusted Comparable Cost (\$000s)	\$47,267	\$52,020	\$43,184	\$51,930

A breakdown of the Project station costs is shown below:

**Table 8: Station Costs<sup>38</sup>**

	Estimated Cost (\$000's)	Percentage (%)
Materials	\$24,595	32%
Labour	\$9,600	13%
Equipment Rental & Contractor Costs	\$27,500	36%
Sundry	\$5	0%
Contingencies	\$6,100	8%
Overhead	\$1,400	2%
Allowance for Funds Used During Construction	\$7,300	10%
Real Estate	-	-
<b>Total Station Work</b>	<b>\$76,500</b>	<b>100%</b>

### Contingency Costs

Hydro One's project cost estimate includes an allowance for contingencies that may

<sup>34</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 13, parts d and e

<sup>35</sup> Exhibit B, Tab 7, Schedule 1

<sup>36</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 13, part f

<sup>37</sup> Exhibit B, Tab 7, Schedule 1, Table 6, p. 12

<sup>38</sup> Exhibit B, Tab 7, Schedule 1, Table 2, p. 1

impact the final project costs upon completion. The contingency allowance is intended to cover the following key project risks:

- Outage Constraints
- Approvals, Permits and Authorizations
- Archaeology Finds

In response to interrogatories from OEB staff requesting more details regarding the costs included in the Contingencies category, Hydro One explained that the contingency amounts for the Project were developed using an industry established, risk-based contingency methodology and stated that contingency valuations are probabilistic and therefore could not provide additional details.<sup>39</sup>

Hydro One provided the information in Table 9 below in response to OEB staff's request to provide cost comparisons for contingency costs for similar projects.

**Table 9: Contingency Cost Comparisons<sup>40</sup>**

Cost Type	Waasigan Project – Phase 1	Waasigan Project – Phase 2	Chatham Lakeshore Project	St Clair Transmission Line Project	Welland Thorold (The Project)
Line Cost	10.5%	9.5%	8.9%	8.4%	14.1%
Station Cost	11.2%	12.3%	4.6%	9.8%	8.0%

Hydro One noted that the Project carries a higher level of contingency costs due to the unique characteristics of the Project, with more impactful owner-side risks tied to the schedule. Further, Hydro One stated that the Project is different from typical greenfield transmission line projects and consists of several distinct stages that require coordination between multiple parties and work groups and, in some cases, outages. Hydro One states that these higher contingency costs also account for higher land acquisition and expropriation risks, and geopolitical and market uncertainty.

#### Early Contractor Involvement - Engineering, Procurement, and Construction

Hydro One stated that a fixed price Early Contractor Involvement (ECI) - EPC execution methodology was selected for the Project. The selection of the EPC contractor used a slight variant of the ECI-EPC process approved in the Waasigan Project<sup>41</sup> and St. Clair

<sup>39</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 10, parts a and b

<sup>40</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 10, part b, Table 3

<sup>41</sup> EB-2023-0198

Transmission Line Project<sup>42</sup> leave to construct applications.<sup>43</sup>

Hydro One also stated that leveraging this model enabled the development of “bespoke and refined solutions” in the execution phase by engaging contractors early in the project lifecycle. For this project, the process included cost development through an “open-book process with full transparency on procurement process, as well as the bottom-up estimation process, including production rates and crew composition.” The use of this modified process allowed Hydro One and the EPC to “appropriately identify and allocate risks between the parties and utilize effective and appropriate solutions to meet the needs of the system.”<sup>44</sup>

Hydro One calculated the overhead cost estimate using the ECI model with an external owner’s engineer, applying the ECI-EPC overhead capitalization rate to both line and station components. Overhead costs were calculated by multiplying the applicable overhead rate with monthly direct capital expenditures.<sup>45</sup>

## Submission

OEB staff submits that Hydro One followed a reasonable process for developing its project cost estimate. Hydro One used a competitive procurement process to select an EPC contractor and used comparative projects to evaluate the Project costs.

OEB staff submits that the comparative projects used by Hydro One are appropriate benchmarks for evaluating the costs of the Project. The inflationary adjustments applied to comparator projects by Hydro One appear reasonable to OEB staff. OEB staff notes that the line and station costs for the proposed Project are largely in line with those of the comparative projects, adjusting for current market conditions. Specifically, Hydro One attributes the slight increase in project costs to the unique scope and requirements of the Project. OEB staff find these justifications reasonable.

OEB staff notes that while the contingency costs form a significant portion of the project costs, and the allocation of 14.1% for line work is higher than comparable projects, Hydro One’s explanation that this is due to the unique risks carried by the Project is acceptable. Contingency cost allocation of 8% for station work is largely in line with comparable projects.

OEB staff is supportive of Hydro One’s ECI-EPC approach for large transmission projects since it leads to early risk identification and more accurate cost estimation. A

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<sup>42</sup> EB-2024-0155

<sup>43</sup> Exhibit B, Tab 7, Schedule 1, p. 2

<sup>44</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 11, part d

<sup>45</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 10, part c

similar approach was also used by Hydro One for the Chatham to Lakeshore Line Project<sup>46</sup>, the Waasigan Transmission Line Project<sup>47</sup> and the St. Clair Transmission Line Project<sup>48</sup>. OEB staff supports the modified approach with an open-book process that was utilized for this project as it allows for appropriate risk identification and solution development. OEB staff recognizes the need to modify certain processes to meet project-specific needs.

OEB staff submits that the overhead capitalization methodology is a rates issue and should be reviewed in the first rate application associated with the Project, consistent with the approach taken for the Chatham to Lakeshore Line Project<sup>49</sup>.

## 2.3 Consumer Impact

### 2.3.1 Cost Responsibility and Allocation

In its application, Hydro One proposed allocating 100% of the station costs to the transformation connection pool, and 100% of the line costs to the network pool.<sup>50</sup>

The Project reinforces the supply to Crowland TS, which is currently supplied by circuits A6C and A7C. In Hydro One's 2021 rebasing application, Crowland TS was categorized as a transformation connection facility and circuits A6C and A7C were categorized as line connection facilities.<sup>51</sup> In OEB staff's view, these categorizations are consistent with the definitions of transformation connection facilities<sup>52</sup> and line connection facilities<sup>53</sup> contained in the OEB's [Transmission System Code \(TSC\)](#).

In response to an interrogatory, Hydro One stated that "Hydro One is not proposing to classify the new 230 kV line as a network facility. The line is properly classified as a connection facility."<sup>54</sup> In response to an interrogatory, Hydro One also stated that Welland Hydro and Hydro One Distribution are the two local distribution companies supplied by Crowland TS.<sup>55</sup>

Under the TSC, the costs associated with connection facilities are typically recovered from the connecting customer(s), while costs associated with network facilities, are recovered from all Ontario ratepayers. Section 6.3.18 of the TSC governs cost

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<sup>46</sup> EB-2022-0140, Decision and Order, November 24, 2022

<sup>47</sup> EB-2023-0198, Decision and Order, April 16, 2024

<sup>48</sup> EB-2024-0155, Decision and Order, December 10, 2024

<sup>49</sup> EB-2024-0216, Decision and Order, December 17, 2024

<sup>50</sup> Exhibit B, Tab 9, Schedule 1, pp. 2-3

<sup>51</sup> EB-2021-0110, Exhibit H, Tab 2, Schedule 1, pp. 4-5 and Exhibit H, Tab 2, Schedule 2, p.6.

<sup>52</sup> Transmission System Code, March 31, 2025, Section 2.0.62, p. 12

<sup>53</sup> Transmission System Code, March 31, 2025, Section 2.0.39, p. 9

<sup>54</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 18, part a

<sup>55</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 15, part c

responsibility for a new or modified transmitter-owned connection facility that also addresses a broader network system need.

Section 6.3.18 and section 6.3.18A are reproduced below:

- 6.3.18 Where one or more customers triggers the need for a new or modified transmitter-owned connection facility and the IESO undertakes an assessment at the request of a transmitter that confirms the new or modified connection facility will also address a broader network system need, the transmitter shall determine the proportional benefit and the related attribution of costs between the triggering customer(s), collectively, and the network pool. The transmitter shall then attribute the collective triggering customer costs to each triggering customer(s) in accordance with the methodology set out in section 6.3.12, 6.3.13, 6.3.14, 6.3.15 or 6.3.16, as applicable.
- 6.3.18A Where section 6.3.18 applies, the transmitter shall apply to the Board for approval of the attribution of costs between the triggering customer(s) and the network pool. Where the Board approves a different attribution of costs, the transmitter shall recalculate the capital contribution to be made by the triggering customer(s).

Evidence provided by the IESO shows that the Project is triggered by forecast load growth at Crowland TS.<sup>56</sup> The Project would benefit the two transmission-connected customers supplied by Crowland TS, Hydro One Distribution and Welland Hydro, by providing increased capacity to supply Crowland TS.<sup>57</sup>

In OEB staff's view, the Project, as described in the evidence, is a modified transmitter-owned connection facility that is triggered by customer load growth at Crowland TS and therefore meets the criteria set out in section 6.3.18 of the TSC.

In response to an interrogatory, in addition to confirming that the line is properly classified as a connection facility, Hydro One noted the applicability of section 6.3.18 with respect to the Project, stating that:

... pursuant to section 6.3.18 of the Transmission System Code (TSC), classification and cost allocation are distinct analytical steps [...] In such circumstances, costs are to be attributed between the triggering

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<sup>56</sup> Exhibit B, Tab 3, Schedule 1, Attachment 1.

<sup>57</sup> The TSC defines "customer" as "a generator, storage customer, consumer, distributor or unlicensed transmitter whose facilities are connected to or are intended to be connected to a transmission system".

customer(s) and the network pool based on relative benefit.<sup>58</sup>

Section 6.3.18 was added to the TSC through an amendment in 2018. In its [Notice of Proposal to Amend a Code](#) (the Notice), the OEB stated:

The OEB generally believes a specific customer should not be required to pay all of the costs associated with a connection investment where the investment also addresses a broader network system need (e.g., reliability). This is consistent with the beneficiary pays principle, since both the customer(s) that caused the need for the investment and the broader system benefit.

While the OEB is generally supportive of recovering a portion of the costs in such cases from all ratepayers, the OEB has some concerns related to implementation within the context of ensuring fair and equitable apportionment. For example, there is a potential incentive to apportion more than the appropriate amount to all ratepayers (i.e., network pool).<sup>59</sup>

The Notice also stated:

There was a provision in the TSC (section 6.3.6) that allowed for apportionment of connection asset costs to the network rate pool. However, that provision was eliminated in a previous OEB proceeding (EB-2011-0043) for a number of reasons. First, it allowed for the apportionment of 100% of the cost to all ratepayers (i.e., non-beneficiaries), even if the primary reason for the investment was to serve a customer's needs. It was therefore inconsistent with the beneficiary pays principle.<sup>60</sup>

OEB staff notes that the OEB describes the potential for apportionment of 100% of the costs for a connection asset to the network pool as inconsistent with the beneficiary pays principle and a weakness of section 6.3.6 that led to the OEB removing it from the TSC.

In OEB staff's view, Hydro One's allocation of 100% of the line costs to the network pool is not consistent with the OEB's beneficiary pays principle and is not consistent with section 6.3.18 of the TSC which the OEB added after removing section 6.3.6.

The Notice includes an illustrative example of how to allocate costs between customers

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<sup>58</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 18, part a

<sup>59</sup> Notice of Proposal to Amend a Code, EB-2016-0003, September 21, 2017, p. 5

<sup>60</sup> Notice of Proposal to Amend a Code, EB-2016-0003, September 21, 2017, p. 5

and the network rate pool using the proportional benefit approach:

The cost of each separate solution to meet the two regional needs is first determined. In this example, the cost is \$30M to address the system need and \$90M to meet the customer(s) need. The aggregate cost of the two solutions is therefore \$120M (\$30M + \$90M). The relative proportion (i.e., percentage allocation of aggregate cost) attributed to each solution is as follows: system need ( $\$30\text{M} / \$120\text{M} = 25\%$ ) and customer(s) need ( $\$90\text{M} / \$120\text{M} = 75\%$ ). Those relative proportions are then applied to the cost of the single integrated optimal solution that addresses both needs at a lower cost (e.g., \$100M or \$20M lower): system need is  $25\% * \$100\text{M} = \$25\text{M}$  and customer need is  $75\% * \$100\text{M} = \$75\text{M}$ . As a result, applying the proportional benefit to the cost of the optimal solution would result in \$25M being recovered from all ratepayers (rather than \$30M under the sub-optimal solution) via the network pool and \$75M would be recovered from the benefiting customer(s) – rather than \$90M.<sup>61</sup>

OEB staff notes that this approach is based on comparing a lower cost integrated solution that addresses multiple regional needs with the total cost of separate solutions to meet the needs. In this case, the needs to be met are the need for increased capacity to supply customers at Crowland TS and the need for increased capacity to supply the broader 115 kV system in the region.

### Submission

OEB staff submits that Hydro One has not correctly determined the need for, and the amount of, any capital contributions that are required for the Project. OEB staff submits that the OEB should not approve Hydro One's request to attribute 100% of the line cost to the network pool and 100% of the station cost to the transformation connection pool because it is inconsistent with section 6.3.18 of the TSC and with the OEB's beneficiary pays principle.

In OEB staff's view, Hydro One should follow the approach set out in section 6.3.18 of the TSC to determine the attribution of costs between the triggering customers, collectively, and the network pool.<sup>62</sup>

In OEB staff's view the same portion of the line cost and the station cost should be allocated to the triggering customers and the network pool because both the line and station costs are required to reinforce the supply to Crowland TS and to address the

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<sup>61</sup> Notice of Proposal to Amend a Code, EB-2016-0003, September 21, 2017, p. 6

<sup>62</sup> [Transmission System Code](#), Section 6.3.18,

broader network system need to supply the 115 kV system.

The IRRP sets out two alternative sets of investments, Option Set 1 and Option Set 2, that address the following four needs:

- Crowland TS asset replacement need
- Crowland TS station capacity need
- A6C/A7C load security need
- Niagara 115 kV sub-system capacity need<sup>63</sup>

Option Set 1 addresses the need for increased capacity to supply customers at Crowland TS and the need for increased capacity to supply the broader 115 kV system in the region separately. The Crowland TS customer needs are addressed by rebuilding Crowland TS, adding a second 115 kV station and uprating circuits A6C/A7C. Option Set 1 also includes a new 230 kV switchyard at Allanburg TS to address the broader network system need for Niagara 115 kV sub-system capacity.

Option Set 2 addresses all needs in a single integrated solution by converting Crowland TS from 115 kV to 230 kV to supply the existing and forecast demand at Crowland TS from the 230 kV system.

The scope of the Project is consistent with Option Set 2 which the IRRP identified as the preferred solution because it addresses the customer needs and broader network system need in an integrated solution at a lower cost than Option Set 1.

The RIP contains the following costs of the components of Option Set 1:

**Table 10: Option Set 1 Component Costs by Beneficiary**

Option Set 1	Cost	Proportion
Components for meeting Crowland TS customer needs	\$101 million	28.5%
Rebuild the 115 kV Crowland TS like-for-like and add a second 115 kV station	\$78 million <sup>64</sup>	
Uprate A6C/A7C circuits to accommodate new 115 kV station	\$23 million <sup>65</sup>	
Components for meeting network needs	\$253 million	71.5%
Add a new 230 kV switchyard at Allanburg TS	\$253 million <sup>66</sup>	
<b>Total Cost</b>	<b>\$354 million</b>	<b>100%</b>

As summarized in Table 10, the cost of meeting Crowland TS customer needs as part of Option Set 1 is \$101 million and the cost of meeting the broader system network

<sup>63</sup> Exhibit H, Tab 1, Schedule 1, Attachment 2, pp.46 of 56

<sup>64</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, p. 35

<sup>65</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, p. 31

<sup>66</sup> Exhibit H, Tab 1, Schedule 1, Attachment 1, pp. 32 and 35

need is \$253 million. The aggregate cost of the two solutions is \$354 million. The relative proportion of each solution (i.e. percentage of aggregate cost) is 28.5% for customer needs and 71.5% for network needs.

Applying the relative proportions to the \$311.4 million total capital cost of the Project (which is consistent with the scope of Option Set 2) would result in attributing \$168 million of the line cost plus \$54.7 million of the station cost to the network pool and the remainder to the line connection pool and the transformation connection pool, respectively.

In summary, OEB staff agrees with Hydro One's statement in the evidence that because the Project consists of 230 kV transmission facilities it provides a network benefit by alleviating the strain on the 115 kV transmission system and provides increased reliability.<sup>67</sup>

However, OEB staff does not agree with Hydro One's proposed approach of allocating 100% of the line costs to the network pool and 100% of the station costs to the transformation connection pool. In OEB staff's view the transmitter should attribute the Project costs, which consist of the line and station costs, between the triggering customer(s), collectively, and the network pool based on the proportional benefits approach set out in section 6.3.18 of the TSC and the direction provided in the Notice. In OEB staff's view, the same proportion should be applied to the line and station costs because they are both connection facilities (being line connection and transformation connection facilities, respectively) and both are required to supply the Crowland TS customers and to realize the broader network benefit by converting Crowland TS to 230 kV supply.

OEB staff notes that section 6.3.15 of the TSC sets out how the transmitter should attribute costs to load customers where more than one load customer triggers the need for a new or modified transmitter-owned connection facility.

### **2.3.2 Transmission Rate Impacts**

In the evidence, Hydro One included the cost of a proposed new switching station, Crowland SS, in the network pool for the rate impact assessment. This is in addition to 100% of the line cost associated with the Project.<sup>68</sup> Crowland SS is not a part of the Project; however, the evidence stated that as a requirement of the Final System Impact Assessment conducted by the IESO, Hydro One has been directed to build the new sectionalizing station.<sup>69</sup> In the evidence, Hydro One stated that the cost associated with

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<sup>67</sup> Exhibit B, Tab 9, Schedule 1

<sup>68</sup> Exhibit B, Tab 9, Schedule 1

<sup>69</sup> Exhibit B, Tab 2, Schedule 1, p. 2

Crowland SS, based on an AACE Class 5 estimate, is \$55.6 million.<sup>70</sup>

The 25-year discounted cash flow analysis based on Hydro One's proposed allocation of costs to the network pool and transformation connection pool included in the evidence shows that the combination of the Project and Crowland SS will have the following impacts for network and transformation pools, after accounting for the assumed impact on future capital cost allowance and Hydro One corporate income tax:

**Table 11: Rate Pool Impacts<sup>71</sup>**

Pool	Initial Cost	Annual Incremental Revenue	Net Present Value
Network	\$290.5 M	\$11.2 M	(\$146.5 M)
Transformation	\$76.5 M	\$5.9 M	(\$12.4 M)

Through interrogatories, Hydro One clarified its NPV analysis to reflect the 2026 UTR rates that were issued after the application was filed.<sup>72</sup>

Hydro One estimated that the Project will increase the typical residential customer bill, under the Regulated Price Plan by \$0.11 per month or 0.07%. This amounts to an increase of approximately \$1.34 per year.<sup>73</sup>

### Submission

Because OEB staff disagrees with the cost allocation proposed by Hydro One, OEB staff takes no position on whether the projected rate impacts contained in the evidence are reasonable.

OEB staff notes that section 6.3.18A of the TSC states that where section 6.3.18 applies, and where the OEB approves a different attribution of costs than what the transmitter applied for, the transmitter shall recalculate the capital contribution to be made by the triggering customer(s).

OEB staff also notes that Hydro One included the costs for Crowland SS, which is not part of the Project, in the rate impact assessment. In response to an interrogatory, Hydro One stated that:

With the present short circuit levels at Beck-2, Middleport TS and Beach TS, a

<sup>70</sup> Exhibit B, Tab 7, Schedule 1, p. 1

<sup>71</sup> Exhibit B, Tab 9, Schedule 1, pp.6-9

<sup>72</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 21, part a

<sup>73</sup> Exhibit B, Tab 9, Schedule 1, pp. 4-5

maximum of 113 MVA per circuit can be added to Q24HM or Q20HM circuits without requiring the installation of the future proposed Crowland SS. Once these thresholds are exceeded, however, Crowland SS is required. It is unknown when loading on the 230 kV circuits will exceed this threshold ...<sup>74</sup>

The interrogatory response goes on to state that despite being a distinct project, Hydro One included the costs associated with Crowland SS in the projected rate impacts in conjunction with the full loading that could be connected once Crowland SS is in-service.<sup>75</sup>

In OEB staff's view, neither the cost of Crowland SS nor the incremental benefit of Crowland SS should be included in the projected rate impact associated with the Project because Crowland SS is a separate investment that will, if undertaken, provide incremental benefits beyond those provided by the Project.

## 2.4 Reliability and Quality of Service

The IESO's final SIA, dated November 19, 2025, concluded that the Project is expected to have no material adverse impact on the reliability of the integrated power system, provided that all requirements in the SIA report are implemented.<sup>76</sup>

Hydro One's Final Customer Impact Assessment (CIA) concluded that "the proposed work will not have any adverse effect on Hydro One transmission customers in the electrical vicinity."<sup>77</sup>

### Submission

OEB staff does not have any concerns about the reliability and quality of service associated with the Project, considering Hydro One's evidence and the conclusions of the IESO's SIA and Hydro One's CIA.

## 2.5 Economic Growth

The OEB's filing requirements for electricity transmission leave to construct applications provide that where an applicant asserts that a project will support economic growth, the applicant should provide evidence supporting this assertion and an indication of the economic growth policies of the government of Ontario that are relevant to the project.<sup>78</sup>

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<sup>74</sup> Exhibit I, Tab 1, Schedule 6, pp. 1-2

<sup>75</sup> *Ibid.*

<sup>76</sup> Exhibit F, Tab 1, Schedule 1, Attachment 1, p. 6

<sup>77</sup> Exhibit G, Tab 1, Schedule 1, Attachment 1, p. 8

<sup>78</sup> [Filing Requirements for Electricity Transmission Applications – Chapter 4: Leave to Construct and Related Matters under Part VI of the Ontario Energy Board Act](#), December 16, 2025, p. 17

In the application, Hydro One did not assert that the Project will support economic growth.

OEB Staff does not make specific submissions regarding economic growth but notes that the related subject of the need to increase transmission supply capacity to meet increasing power demands in the Niagara region is discussed in these submissions in section 2.1 Project Need & Project Alternatives.

## 2.6 Landowner Agreements

The total route length of the proposed transmission line corridor is 18.5 km. The line will be sited within a corridor 30 metres wide for the majority of the length with some stretches varying up to 49 metres wide. The corridor is anticipated to impact approximately 72.3 hectares of land, the distribution of which is shown in Table 12 below.<sup>79</sup>

**Table 12: Summary of Property Types and Sizes Required**

Land Ownership Type	Count	Area (Hectares)	Proportion of the Route (%)
Private Lands	46	37.54	52%
Brownfield	31	23.22	32%
Greenfield	15	14.32	20%
Federal Lands	3	5.75	8%
Provincial Lands	6	0.59	1%
Municipal Lands	7	4.53	6%
Railway Lands	3	0.47	1%
<b>No New Rights Required</b>			
Provincial Lands (Bill 58 – Hydro One owned land)	22	18.42	25%
Public Road Allowance	37	4.29	6%
Private Land Already Acquired	1	0.73	1%
<b>Total</b>	<b>125</b>	<b>72.31</b>	<b>100%</b>

Hydro One stated that the Project aligns with the *Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2024* as the Project makes use of existing infrastructure and facilities and, where possible, uses existing transmission corridor lands and existing Rights of Way.<sup>80</sup>

<sup>79</sup> Exhibit E, Tab 1, Schedule 1

<sup>80</sup> Exhibit E, Tab 1, Schedule 1

As shown in Table 12, the Project will require Hydro One to acquire land rights from 65 directly impacted properties, consisting of 46 privately held properties, 3 federally held properties, 6 provincially held properties, 7 municipally held properties, and 3 railway crossings. Hydro One requires permanent interest from property owners and has achieved early access agreements on approximately 78% of the private properties that require new land rights.<sup>81</sup> As of March 2026, Hydro One had secured 2 additional voluntary settlement agreements with private landowners.<sup>82</sup> If Hydro One is unsuccessful in securing all required land rights via voluntary agreements, the application states that Hydro One intends to seek expropriation authority over those lands in a future application to the OEB.<sup>83</sup>

The Project corridor will include a combination of the following land rights requirements:

- Hydro One License of Occupation on Federally owned lands and/or easements.
- Permanent Easement rights on private and municipal/provincial properties (new land rights required).
- Rail crossing agreements (new land rights required).
- Temporary access and/or construction rights on federally, provincially, municipally owned and private properties for access roads, temporary work headquarters, laydown areas, and material storage facilities (new land rights required).

Table 13 below lists the different land rights agreements that Hydro One stated may be required, including details on the extent to which the forms of agreement have previously been approved by the OEB in prior proceedings.

In its response to interrogatories, Hydro One stated that it is changing its land acquisition strategy as a result of Procedural Order No. 2, whereby the OEB established that the leave to construct and expropriation relief aspects of this proceeding would not be addressed concurrently. Specifically, Hydro One is moving from pursuing option agreements to presenting an “Agreement to Purchase a Limited Interest – Easement” with a signing bonus if exercised prior to June 30, 2026. Hydro One stated that the aim of this change is to accelerate the land acquisition process so that Project timelines are maintained by minimizing the need for expropriation relief. Hydro One stated that this change in approach is not expected to increase forecast costs.<sup>84</sup>

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<sup>81</sup> Exhibit I, Tab 1, Schedule 1, pp. 1-4

<sup>82</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 25, part a

<sup>83</sup> Exhibit I, Tab 1, Schedule 1, p. 7

<sup>84</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 25, part a

**Table 13: Forms of Land Rights Agreements and Prior OEB Approvals**

<b>Form of Agreement</b>	<b>Previous OEB Docket</b>
Early Access Agreement	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 3
Option to Purchase a Limited Interest – Easement	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 4
Compensation and Incentive Agreement – Easement	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 5
Option to Purchase a Limited Interest – Easement with a Voluntary Buyout Offer	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 8
Agreement for Temporary Rights	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 9
Off Corridor Access	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 10
Crop Land Out of Production Agreement	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 11
Damage Claim Agreement/Waiver	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12
Agreement to Purchase a Limited Interest – Easement	Not Applicable

## Submission

OEB staff has reviewed the proposed forms of agreement and has no issues or concerns. With the exception of the Agreement to Purchase a Limited Interest – Easement agreement, the proposed forms of agreement are consistent with ones approved by the OEB through previous proceedings.

In response to an interrogatory, Hydro One stated that all impacted property owners will be advised during property acquisition discussions that they have the option to receive independent legal advice and that it would commit to reimbursing those property owners for reasonably incurred legal fees associated with the review and completion of the necessary land rights.<sup>85</sup>

## 2.7 Conditions of Approval

The OEB Act permits the OEB, when making an order, to impose such conditions as it considers proper. The OEB has established a set of [standard conditions of approval for transmission Leave to Construct applications](#).

<sup>85</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 25, parts c-e

**Submission**

OEB staff proposes that the standard conditions of approval be placed on Hydro One. The proposed conditions have been approved by the OEB in prior leave to construct applications. Hydro One has confirmed that they agree with the standard conditions of approval.<sup>86</sup>

~All of which is respectfully submitted~

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<sup>86</sup> Interrogatory Responses, Exhibit I, Tab 1, Schedule 26