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BY EMAIL AND RESS

January 30, 2026

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

Dear Mr. Murray,

EB-2026-0003 – Hydro One Networks Inc. Leave to Construct Application – M31W Reinforcement Project – Application and Evidence

Pursuant to Section 92 of the Ontario Energy Board Act, 1998, (the "Act"), Hydro One Networks Inc. ("Hydro One") seeks the Ontario Energy Board's ("OEB") approval for an Order or Orders granting leave to construct transmission facilities ("M31W Reinforcement Project" or "Project") in southwestern Ontario in the City of London.

Additionally, pursuant to Section 97 of the Act, Hydro One seeks OEB approval for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

Hydro One is confirming that the documents filed in support of the referenced application do not include any personal information under the Freedom of Information and Protection of Privacy Act (Ontario) ("FIPPA") with respect to this Application. Any FIPPA related information in the Application has been redacted. Furthermore, Hydro One is confirming that the System Impact Assessment ("SIA") report appendices, which contain confidential information, have been omitted from this Application. This approach is consistent with Chapter 4 (Section 4.3.6) of the OEB's Filing Requirements for Electricity Transmission Applications.

Hydro One further consents that this proceeding be disposed of without a hearing pursuant to section 21(4) of the OEB Act, given that this Project will not adversely affect customers in any material way. Specifically, the Customer Impact Assessment and the SIA have confirmed that the Project will have no material adverse impact on customers or the reliability of the integrated power system. The Project will reduce transmission line losses in a cost-effective manner and require no new permanent land rights. Furthermore, the Project is forecast to reduce the network pool rate and overall average Ontario consumer's electricity bill.

An electronic copy of this Application and Evidence has been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

Pasquale Catalano

EXHIBIT LIST

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LIST OF ACRONYMS AND ABBREVIATIONS

Acronym or Abbreviation	**Acronym or Abbreviation Expansion**
A	Amperes
AACE	Association for the Advancement of Cost Engineering *(estimate classification system)*
ACSR	Aluminium-Conductor Steel-Reinforced cable
ACSS/TW	Aluminium-Conductor Steel-Supported, trapezoidal shaped cable
AFUDC	Allowance for Funds Used During Construction
C	Celsius
CIA	Customer Impact Assessment
Class EA	Class Environmental Assessment
DCF	Discounted Cash Flow
Hydro One *(HONI)*	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
ISOC	Integrated System Operating Center
JCT	Junction
kcmil	Kilo-circular mils *(unit of measure of the area of a wire with a circular cross section)*
km	Kilometer
kV	Kilovolt
kW	Kilowatt
MECP	Ministry of the Environment, Conservation and Parks
MW	Megawatt
MWHR *(or MWH)*	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
OEB	Ontario Energy Board (the Board)
OMA	Operations, Maintenance and Administrative costs
PIN	Property Identification Number
PV	Present Value

Acronym or Abbreviation	Acronym or Abbreviation Expansion
RIP	Regional Infrastructure Plan
ROE	Return on Equity
ROW	Right-of-Way
RPP	Regulated Price Plan
SIA	System Impact Assessment
TS	Transformer Station
TSC	Transmission System Code
TSP	Transmission System Plan
UTR	Uniform Transmission Rates

ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998 (the "Act")*;

AND IN THE MATTER OF an Application by Hydro One Networks Inc. ("**Hydro One**") pursuant to section 92 of the Act for an Order or Orders granting leave to construct transmission line facilities ("**M31W Reinforcement Project**" or "**Project**") in southwestern Ontario in the City of London.

AND IN THE MATTER OF an Application by Hydro One pursuant to section 97 of the Act for an Order granting approval of the forms of land use agreements offered or to be offered to affected landowners.

APPLICATION

1. The Applicant is Hydro One, a subsidiary of Hydro One Inc. The Applicant is an Ontario corporation with its head office in the City of Toronto. Hydro One carries on the business, among other things, of owning and operating transmission facilities within Ontario.

2. Hydro One hereby applies to the OEB pursuant to section 92 of the Act for an Order or Orders granting leave to reconstruct a section of an existing 230 kV single-circuit transmission line (M31W) between Buchanan TS and Old Victoria Road Junction within the City of London. The approximate length of the transmission line facilities is 4 km.

3. The Project is required to maintain the capability of the bulk system while increasing the supply transfer capability thereby ensuring continued, reliable bulk supply to the London Area, as outlined by the IESO in the bulk planning report provided as **Attachment 1** in **Exhibit H, Tab 1, Schedule 1**. The IESO further reaffirmed this

need in their supplemental evidence provided for the purposes of this Application in **Attachment 1** of **Exhibit B, Tab 3, Schedule 1**. The Project has been identified as a non-discretionary development project in **Exhibit B, Tab 4, Schedule 1**.

4. The 230 kV conductor selected by Hydro One to complete the Project has been predicated on Hydro One's commitment to minimize transmission line losses where feasible. Further information regarding the transmission line loss analysis for this Project is provided in **Exhibit B, Tab 5, Schedule 1**.

5. An overview map of this area is provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1**, and a schematic diagram of the proposed Project can be found at **Exhibit B, Tab 2, Schedule 1, Attachment 2**.

6. The existing transmission corridor will provide sufficient width for the proposed Project. The existing transmission corridor is exclusively situated on Bill 58 lands over which Hydro One holds a statutory easement, except for, where necessary, crossing perpendicularly over public roads. As a result, no new permanent land rights on properties between Buchanan TS and Old Victoria Road Junction will be required to accommodate the proposed transmission facilities. Further information regarding Hydro One's real estate needs to complete this Project are provided in **Exhibit E, Tab 1, Schedule 1**.

7. In accordance with the Class EA for Transmission Facilities[1], the reconstruction of the existing 230 kV transmission line as outlined in this Application is exempt from the requirements of the *Environmental Assessment Act,* contingent upon the completion of the Archaeological Screening Process. A Notice of Project Screening will be provided to the MECP in early 2026 to document that Hydro One has followed the Archaeological Screening Process.

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[1] Class Environmental Assessment for Transmission Facilities (February 2024), Section 1.3.2

8. The proposed in-service date for the Project is February 2027, assuming a construction commencement date of July 2026 and OEB approval of this Application by June 2026. A project schedule consistent with the aforementioned assumptions is provided at **Exhibit B, Tab 11, Schedule 1**.

9. The IESO has completed a Final SIA. The Final SIA concludes that the Project is expected to have no material adverse impact on the reliability of the integrated power system and recommends that a *Notification of Conditional Approval for Connection* be issued. The IESO's Final SIA is provided as **Exhibit F, Tab 1, Schedule 1, Attachment 1**.

10. Hydro One has completed a Final CIA in accordance with Hydro One's connection procedures. A copy of the Final CIA is provided as **Exhibit G, Tab 1, Schedule 1, Attachment 1**. Hydro One will fulfill all requirements of the SIA and the CIA, and will obtain all necessary approvals, permits, licences, certificates, agreements, and rights required to construct the Project.

11. The total capital cost forecast for the Project transmission facilities is $15.4 million[2]. Details pertaining to the cost are provided at **Exhibit B, Tab 7, Schedule 1**.

12. The Project will increase the supply transfer capability by 300MW and maintain the reliability and integrity of the transmission system. The expected rate impact associated with the Project (using 2025 OEB-approved uniform transmission rates as filed in **Exhibit B, Tab 9, Schedule 1**) is a $0.09/kW/month decrease in the network pool rate and a 0.09% decrease on the overall average Ontario residential customer's electricity bill.

13. Hydro One will require temporary off-corridor access to facilitate entry for the construction of the transmission facilities. As such, this Application is also seeking

[2] There will be an additional $0.8M of OMA removal costs associated with constructing this Project.

approval of the forms of the agreement offered or to be offered to affected landowners, pursuant to section 97 of the Act. These agreements are in the same form as previously approved in prior Hydro One leave to construct proceedings. The forms of the applied-for agreements are found as attachments to **Exhibit E, Tab 1, Schedule 1**.

14. The Application is supported by written evidence which includes details of the Applicant's proposal for the transmission line. The written evidence is prefiled and may be amended from time to time prior to the Board's final decision on this Application.

15. Based on the foregoing, and the information provided in the prefiled evidence, Hydro One submits that the Project is in the public interest. The Project meets the need to maintain the capability of the bulk system and reduces the price paid by ratepayers.

16. Hydro One consents to the conditions outlined in the OEB's standard conditions of approval for electricity transmission leave to construct applications[3] for this Project.

17. Hydro One further consents that this proceeding be disposed of without a hearing pursuant to section 21(4) of the OEB Act. As is documented in the CIA there are no directly connected customers that are adversely affected by this Project. The IESO's SIA confirms that the Project will have no material adverse impact on the reliability of the integrated power system. The Project reduces transmission line losses in a cost-effective manner and requires no new permanent land rights to complete. The Project will ensure continued, reliable bulk supply to the area, and is forecast to reduce the network pool rate and the overall average Ontario consumer's electricity bill. Given all of the above, Hydro One concludes that this Project will not adversely affect customers in any material way.

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[3] OEB's Standard Conditions of Approval for Electricity Leave to Construct Applications: https://www.oeb.ca/sites/default/files/issues-list-LTC-electricity.pdf

18. Hydro One requests that a copy of all documents filed with the Board be served on the Applicant and the Applicant's counsel, as follows:

a) **The Applicant:**

Eryn Mackinnon
Regulatory Advisor
Hydro One Networks Inc.

Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, Ontario M5G 2P5
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b) **The Applicant's Counsel:**

Monica Caceres
Assistant General Counsel
Hydro One Networks Inc.

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Electronic access:	monica.caceres@hydroone.com

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PROJECT OVERVIEW DOCUMENTS

Hydro One is seeking approval to reconstruct existing transmission facilities between Buchanan TS and Old Victoria Road Junction within the existing corridor. More specifically, the relief sought in this Application satisfies the IESO's recommendation[1] to reconstruct the existing 230 kV single-circuit transmission line (M31W) with higher capacity conductor strung on new double-circuit towers capable of accommodating a second circuit in the future if/when required to increase the transfer capability and maintain load security across the region.

The following proposed facilities are subject to section 92 approval:

- Approximately 4 km section of 230 kV single-circuit transmission line, strung on double-circuit towers, from Buchanan TS to Old Victoria Road Junction within the existing transmission corridor; and
- Minor modifications to the 230 kV transmission line protection settings at the terminal stations, Buchanan TS and Middleport TS.

A map showing the geographic location of the existing facilities as well as schematic diagrams of the proposed facilities are provided in **Exhibit B, Tab 2, Schedule 1, Attachment 1** and **Exhibit B, Tab 2, Schedule 1, Attachment 2**, respectively.

The transmission system in the area requires reinforcement to meet the requirements of the IESO Central-West Bulk Plan. The needs include increasing the supply transfer capability and maintaining load security in order to maintain the capability of the bulk network system. The Project will also preserve the option to add a second circuit if/when it is required. The second circuit would further increase the transfer capability and maintain load security across the region.

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[1] As outlined in the IESO Central-West Bulk Plan provided as Attachment 1 in Exhibit H, Tab 1, Schedule 1.

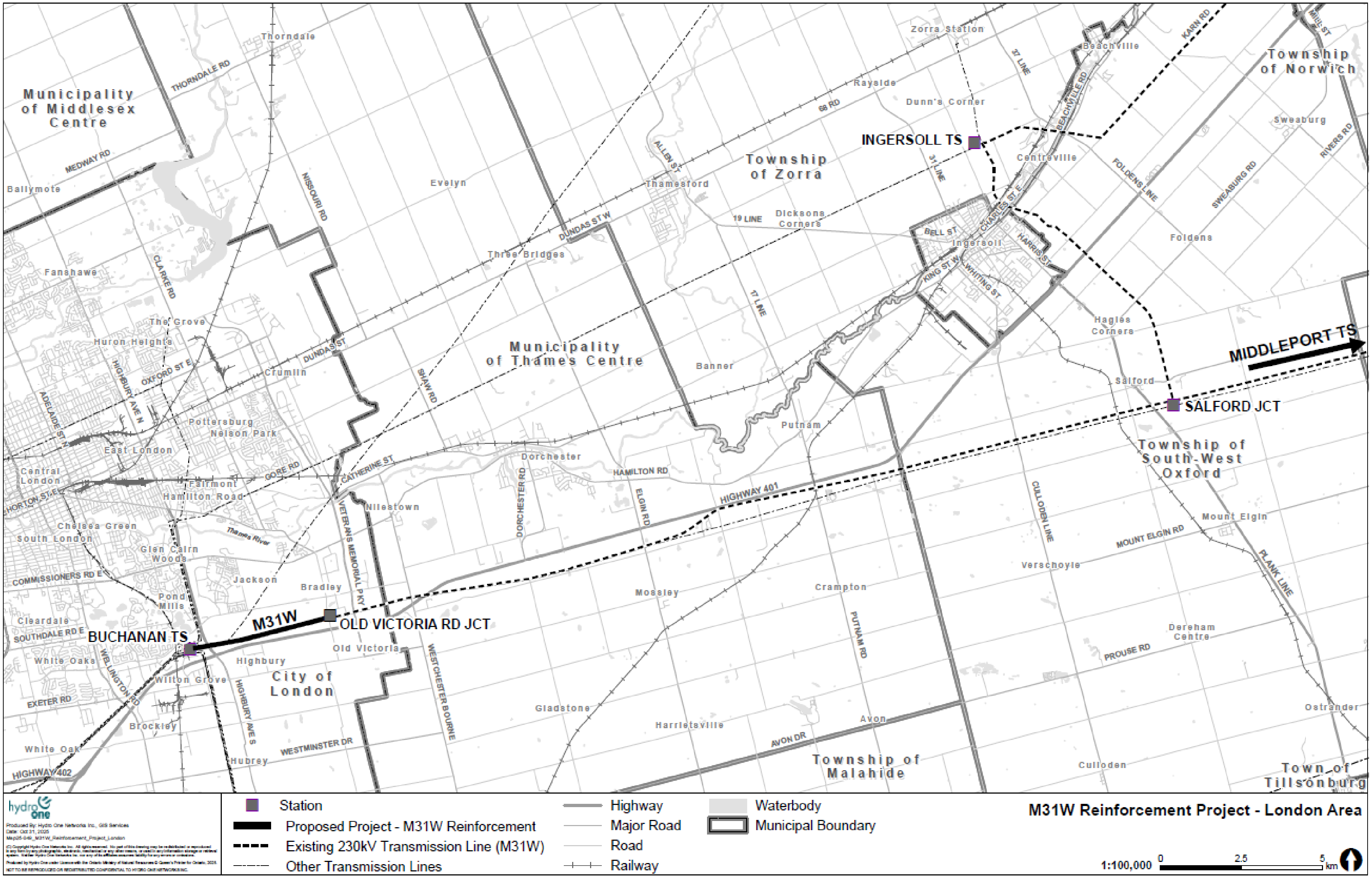
Further information on the proposed facilities is provided below.

Overhead Transmission Line

There are three existing transmission circuits connecting Buchanan TS and Middleport TS, one 230 kV single-circuit transmission line known as M31W and one 230 kV double-circuit transmission line known as M32W/M33W. The proposed Project is to reconstruct the existing 230 kV single-circuit transmission line (M31W) from Buchanan TS to Old Victoria Road Junction, with higher capacity 230 kV double-circuit towers, strung with one circuit but capable of accommodating a second circuit in the future. The total route length of the reconstructed line section is approximately 4 km. The transmission route will utilize the existing transmission corridor which is adjacent to Highway 401 in the City of London. Further details on the physical design for the line and routing are provided in **Exhibit C, Tab 1, Schedule 1**. A schematic diagram showing the proposed transmission line is provided at **Attachment 2 to this Schedule**. The Project may also require minor modifications to the 230 kV transmission line protection settings at Buchanan TS and Middleport TS as further outlined in **Exhibit C, Tab 1, Schedule 1**.

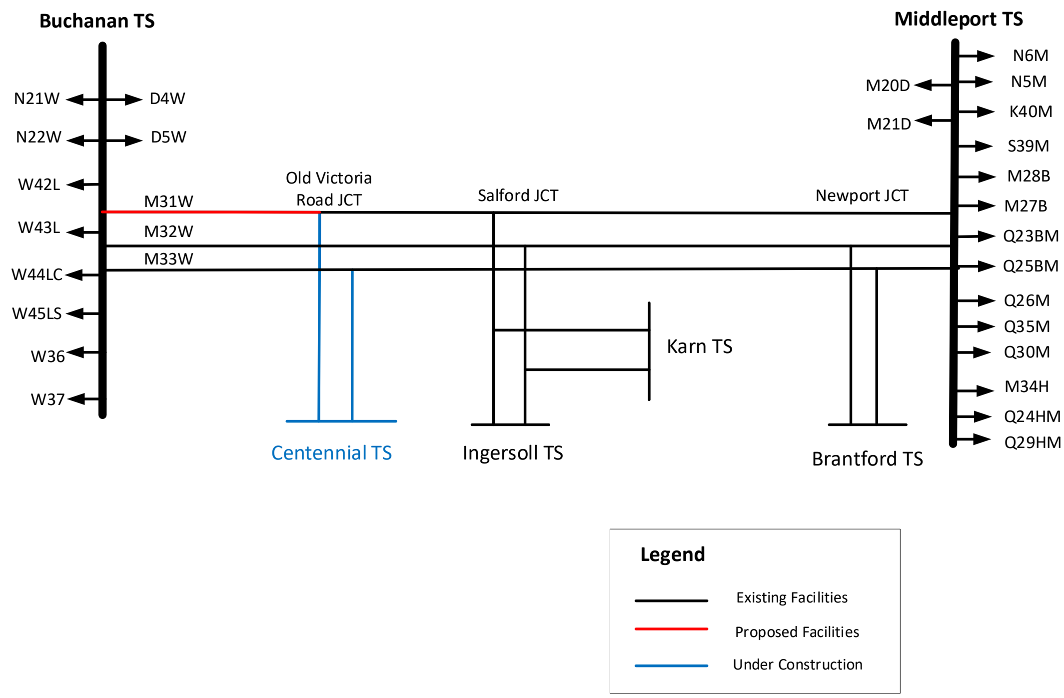
1

GENERAL AREA MAP



PROPOSED FACILITIES:

BUCHANAN TS TO MIDDLEPORT TS 230 KV SCHEMATIC DIAGRAM



EVIDENCE IN SUPPORT OF NEED

The Project is needed to maintain the capability of the bulk system while increasing the supply transfer capability by 300 MW. This need was identified by the IESO in its bulk planning report entitled "Central-West Bulk Plan Report" dated April 18, 2024, which is provided as **Attachment 1** in **Exhibit H, Tab 1, Schedule 1**. The bulk plan report further details that the need to reinforce the transmission system will:

- Ensure continued, reliable bulk supply to the area, and
- Preserve the option to increase system capability in the future, while maintaining load security.

Hydro One is obligated to provide facilities required to maintain the reliability and integrity of its transmission system and reinforce or expand its transmission system as required to meet load growth in accordance with its Transmission License and the TSC. Not proceeding with this investment would result in Hydro One not meeting its obligation and not addressing the need to increase the supply transfer capability and maintain the reliability and integrity of the transmission system.

For the purposes of this Application, the IESO has supplemented this need evidence with **Attachment 1 of this Schedule** entitled "*Supplemental Evidence to Support the Need for the M31W Reinforcement Project*" dated December 15, 2025, which reaffirms the need for the Project to provide bulk system benefits as defined in this Application.

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Supplemental Evidence to Support the Need for the M31W Reinforcement Project

Independent Electricity System Operator

1. Executive Summary

The Independent Electricity System Operator ("IESO") is providing this report in support of the Leave-to-Construct ("LTC") application for the M31W Reinforcement project (the "Project") in accordance with Chapter 4 of the Ontario Energy Board's ("OEB") Filing Requirements for Electricity Transmission Applications (the "Filing Requirements").

Section 4.3.2.3 of the Filing Requirements requires the applicant to provide evidence that identifies the recommended and planned transmission and non-wire projects in any regional plans and/or bulk plans that have "linkages and/or interdependencies to the applied-for transmission project." In the context of an LTC application, "linkages and/or interdependencies" refers to projects (including the Project) where the impact of one or more recommended and planned transmission and non-wire projects has the potential to affect the need for, or viability of, another such project. Section 4.3.2.3 further specifies that "[s]uch projects, or those under consideration as part of an ongoing planning process, might span multiple regions."

The need and rationale for the Project is detailed in IESO's Central-West Bulk Plan[1] published April 2024. This Project is key to the bulk transmission plan recommended to ensure continued, reliable bulk supply to the London Area region due to economic development. The Project will relieve the unacceptable impact to the transfer capability and increase the supply capability by approximately 300 MW, representing a significant portion of the next pocket of "potential load" in the London Area region beyond the firm load (i.e., approximately 900 MW in total) as described in the Central-West Bulk Plan.

The purpose of this report is to provide the OEB with the most up-to-date and complete information to assess the LTC application for the Project given that the Central-West Bulk Plan was published in 2024. This report supplements the 2024 Central-West Bulk Plan by providing evidence on the linkages between the Project and the bulk and regional plans for Southwestern Ontario. Overall, electricity demand in the London Area region is growing, aligned with the load growth assumptions in the Central-West Bulk Plan, further reinforcing the need for the Project. If the OEB does not approve the Project, the IESO will need to reassess its bulk supply plan for the London Area region to ensure the identified need is addressed through alternative measures.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/central-west-bulk-planning/CWBP-20240418-Central-West-Bulk-Plan-Report.pdf

2. Project Background

The IESO's role in the transmission planning and development process is to determine the need, evaluate alternatives, and recommend the most effective solution to adequately address the need.[2] The IESO describes the results of the planning assessment leading to its recommendation to proceed with the Project in the Central-West Bulk Plan[3] report from April 2024 (the "Central-West Bulk Plan").

During previous bulk system planning in Southwestern Ontario, the IESO prepared the 2021 West of London bulk study which identified an electricity supply need. The IESO recommended a new double-circuit 230 kV line between Lambton Transformer Station (TS) and Chatham Switching Station (SS). The IESO also recommended a new single-circuit 500 kV line between Longwood TS and Lakeshore TS. The required in-service years for these transmission reinforcements are presently 2027 and 2030, respectively. The 2021 West of London bulk study also recommended contracting at least 550 MW of local generation resources in the West of London area, which has since been successfully completed.

The Project builds upon these transmission projects from the 2021 West of London bulk study by recommending reinforcement of the M31W circuit to address the impact to the transfer capability of the bulk transmission interface (Negative Buchanan Longwood Input, or "NBLIP") as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC). In particular, and as further described in the Central-West Bulk Plan, the Project supports the Firm Load of 620 MW as well as approximately 300 MW of potential load in the London Area region (i.e., approximately 900 MW in total). The Central-West Bulk Plan also considered the dynamic voltage support needed if more than approximately 900 MW of major economic development (firm load and additional unconfirmed economic development, defined as "potential load") is added in the London Area region.

The Central-West Bulk Plan recommends the following as the most cost-effective options to mitigate forecast demand growth risk, accommodate firm load and potential load growth, and preserve options to increase system capability across the Central-West area over the long term:

- Reconstruct the M31W circuit between Buchanan TS and the firm load tap point, approximately 2-5 km in length, with higher capacity double circuit towers, strung with one circuit but capable of accommodating a second circuit in the future, if/when needed. This recommendation represents the Project.
- If more than 300 MW of potential load materializes in the London Area region, implement dynamic voltage devices at Ingersoll TS, as well as across the Central-West area as demand grows. Since this was an uncertain and long-term need, the Central-West Bulk Plan did not recommend firm timing or location for these options.

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[2] As per the *Electricity Act, 1998*, within the context of regional planning the IESO has responsibility to: engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario; conduct independent planning for electricity generation, demand management, conservation and transmission; and to collect and make public information relating to the short term, medium term and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs.

[3] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/central-west-bulk-planning/CWBP-20240418-Central-West-Bulk-Plan-Report.pdf

The IESO's intent in recommending a staged plan was to closely match developments with the underlying need to maximize the value and effectiveness of each stage, as documented in the Central-West Bulk Plan. More specifically, if there are changes to the need, the staged approach allows the IESO to reassess its recommendations based on real-time circumstances.

Since 2024, the IESO has continued to monitor and plan for the London Area region, and through the following studies, the impact of which being detailed in Section 3:

- The 2024 Burlington to Nanticoke Integrated Regional Resource Plan ("IRRP");
- The ongoing South and Central Bulk Plan; and
- The ongoing London Area IRRP.

The results of the IESO's ongoing assessment reinforce the need established in the 2024 Central-West Bulk Plan, and the necessity of the Project.

3. Relationship of the Project to Southwestern Ontario Plans

The Project has potential linkages with three other plans – the 2024 Burlington to Nanticoke regional plan, the ongoing South and Central bulk plan, and the ongoing London Area regional plan. The Project was included in the Burlington to Nanticoke regional plan and the South and Central bulk plan assessments. The opportunity to leverage the Project to string a second conductor on the new higher capacity double circuit towers was also considered in both plans, but other reinforcements are required to address the needs of those plans beyond the Project. However, the Project is an element of the overall solution and is necessary independent of future bulk transmission investments. The need for the Project remains as it provides bulk system benefits, as described in Section 2, and further enables potential transmission options for reliable supply within the London Area region, as outlined in Section 3.3. Linkages to these three plans are provided in the following sections.

3.1 Burlington to Nanticoke Region

The Burlington to Nanticoke region includes all or part of the following Counties and Districts: City of Hamilton, County of Brant, the City of Brantford, Haldimand County, Norfolk County, the City of Burlington and the Town of Oakville. For the purposes of the regional planning, the Burlington to Nanticoke region was divided into four subregions: Brant, Bronte, Caledonia-Norfolk, and Hamilton. The Brant subregion has linkages to this Project, for which regional planning was completed through the 2024 Burlington to Nanticoke IRRP in December and the 2025 Burlington to Nanticoke Regional Infrastructure Plan in June 2025.

The key IRRP outcomes relevant to the Project were the recommendations for new transmission lines from the City of Cambridge into the County of Brant and two new stations in the County of Brant. Leveraging the existing 230 kV circuits between Middleport TS and Buchanan TS (M31W, M32W, or M33W, referred to here collectively as the "MxW corridor") was considered as an alternative to this recommendation. Due to the high forecasted loading on these circuits, the IRRP identified additional reinforcement would be required to use the MxW corridor. The reinforcement would be approximately 20 km of the 100 km length of the MxW corridor, starting from Middleport TS. Thus, the Project and provision for another circuit on the M31W towers for the first few kilometers from Buchanan TS is not a viable option to address the need in Brant since there is no overlap in the two sections of the MxW corridor. To leverage the provision of this Project to address this need, the entirety of M31W would need to be rebuilt and strung with a second conductor. This would be less cost-effective than the IRRP's recommendation to proceed with the Project. Additionally, using these circuits for load connection would have a negative impact on the bulk interface.

3.2 South and Central Bulk Plan

The IESO is undertaking a South-Central Bulk Plan, to determine the bulk transmission required to enable reliable supply under various long-term high growth, economic development and electrification scenarios within key growth areas in the Greater Toronto Area and the Windsor to Hamilton corridor. The Windsor to Hamilton corridor is defined as five regions in Southwestern Ontario,[4] of which the Project falls within the London Area region. The scope of this study is limited to the bulk system, which includes the 500 kV system and key parts of 230 kV system, while specific load connection details and associated local concerns are out of scope.

The South and Central Bulk Plan is leveraging the 2025 Annual Planning Outlook (2025 APO) load forecast, focusing on the 2035 to 2040 period. A relevant contributing factor to the base 2025 APO growth is the planned Volkswagen EV plant, which is expected to significantly increase the region's electricity demand. Similar to the Central-West Bulk Plan, this study is also considering additional potential incremental load growth across the broader Windsor to Hamilton area, including 700 MW in the London Area region.

To accommodate the significant anticipated increase in electricity demand, the South and Central Bulk Plan explored options to enhance the bulk transmission system into and across the London Area region. This includes potential upgrades to the bulk transfer interface, NBLIP, through various 500 kV circuit reinforcement alternatives, as well as the possible establishment of a new 500 kV supply station in St. Thomas. These measures are particularly important, as rising demand near Buchanan TS is expected to further degrade the NBLIP transfer capacity.

[4] The five regions with the Windsor to Hamilton corridor are London Area, Kitchener-Waterloo-Cambridge-Guelph, Windsor-Essex, Chatham-Kent/Lambton/Sarnia, and Burlington to Nanticoke.

While the Project is a necessary element of the overall solution for Southwestern Ontario, given the magnitude of the projected load growth being considered as part of the South and Central Bulk Plan, further bulk reinforcements are necessary beyond the Project and utilizing the provision for another circuit alone to preserve the bulk interface capacity. This provision may be more appropriate for future projects seeking to connect along the MxW corridor at lower load levels. While such connections could reduce bulk interface capacity, the impact would be mitigated if broader enhancements to the bulk system—such as the 500 kV upgrades being studied in the South and Central Bulk Plan—are implemented.

3.3 London Area Region

The London Area region is located in Southwestern Ontario and includes all or part of the following municipalities: City of London, City of St. Thomas, City of Woodstock, Elgin County,[5] Middlesex County,[6] Norfolk County, and Oxford County.[7]

Regional planning is ongoing in the London Area region, with the IRRP scheduled for completion in October 2026. While bulk planning considers electricity transfers across the province – including from the rest of the province into the London Area region – the IRRP is limited to the consideration of electricity transmission within the London Area region.

London is emerging as one of Canada's fastest-growing urban centres, driven by significant industrial developments and evidenced by a ten per cent population increase between 2016 and 2021. As a result of past growth, local municipalities are planning up to 985 acres of industrial land redevelopment and over 120,000 housing developments into 2050. These trends underscore the need for strategic planning and infrastructure reinforcement to support the London Area region's expanding electricity requirements.

The London Area Needs Assessment Report projected 620 MW of net, coincident peak load growth across the region for the ten-year period of 2024 to 2033, under the Reference scenario. The IRRP will update the load forecast for the 20-year period of 2025 to 2044 and assess regional electricity needs. The provision of double-circuit towers for the Project will provide a pathway for additional transmission in the region, which will be considered during the IRRP when analyzing potential solutions and making recommendations to address identified regional needs. Recommendations from the ongoing South and Central Bulk Plan will also be incorporated into the decision-making process for the IRRP, particularly when considering the long-term supply for the region.

---

[5] Comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold.

[6] Comprising Municipality of Adelaide Metcalfe, Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury.

[7] Comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra.

4. Near-Term Impact to Reliability

As outlined in Section 3.1, load growth in the London Area region is in line with the firm load projections included in the 2024 Central-West Bulk Plan. Even assuming the transmission recommendations in the area including this Project are implemented, there are concerns regarding how to maintain reliability in the near term until those reinforcements can come into service.

Prior to the completion of the Project and other potential bulk and regional reinforcement recommendations, near-term load connections will be subject to a lower level of reliability. Load interruption may need to be coordinated to facilitate outages. At this time, the reliability risks are expected to be limited based on load connection timelines and there are actions available to manage them, including a remedial action scheme and operational coordination. However, operations will become more challenging if load continues to grow faster than forecast before the in-service of this Project.

5. Future Planning in Southwestern Ontario

The IESO is planning to conduct a phase two of the South and Central Bulk Plan in the future, which will continue to look at supporting demand growth in key load centers, determining transmission required to enable generation changes, and maintaining bulk transfer capacity on the transmission circuits that connect the West, Southwest and Greater Toronto Area Zones. The scope of this study is yet to be defined, but updates will be provided through the IESO's Annual Planning Outlooks and quarterly bulk engagements.

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PROJECT CATEGORIZATION AND CLASSIFICATION

PROJECT CATEGORIZATION

Subsection 4.3.2.4 of the Board's Filing Requirements requires applicants to categorize projects as being either discretionary or non-discretionary. Non-discretionary project characteristics include:

a) mandatory requirements to satisfy reliability standards set by standards authorities including NPCC/NERC or the IESO;
b) a need to connect new load (of a distributor or large user) or new generation connection;
c) a need to address equipment loading or voltage/short circuit stresses when their rated capacities are exceeded;
d) a transmission project that the transmitter is required by its licence to develop and seek approvals for;
e) projects identified in a provincial government approved plan;
f) projects that are required to achieve provincial government objectives that are prescribed in governmental directives or regulations; and
g) priority transmission projects declared by Lieutenant Governor in Council order that the construction, expansion, or reinforcement of an electricity transmission line is needed as a priority project.

Based upon the above criteria, Hydro One submits that the Project is properly categorized as a non-discretionary project as it is being undertaken in accordance with direction from the IESO in the regional planning process described in **Exhibit B, Tab 3, Schedule 1.** The Project will increase the supply transfer capability of the bulk system and maintain load security in the area.

PROJECT CLASSIFICATION

Projects are classified into three groups based on their purpose.

- Development Projects, which most closely align with the System Service category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which:
  i. provide an adequate supply capacity and/or maintain an acceptable or prescribed level of customer or system reliability for load growth or for meeting increased stresses on the system; or
  ii. enhance system efficiency such as minimizing congestion on the transmission system and reducing system losses.

- Connection Projects, which most closely align with the System Access category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which provide connection of a load or generation customer or group of customers to the transmission system.

- Sustainment Projects, which most closely align with the System Renewal category as defined in Chapter 5 of the OEB Filing Requirements for Utility System Plans, are those which maintain the performance of the transmission network at its current standard or replace end-of-life facilities on a “like for like” basis.

Based on the above criteria, the Project is a Development Project as the proposed transmission facilities increase supply transfer capability and maintain reliability and integrity of the bulk electricity supply.

Categorization and Classification

		Project Need	
		Non-Discretionary	Discretionary
Project Class	Development	**X**	
	Connection		
	Sustainment		

COST BENEFIT ANALYSIS AND OPTIONS

1.0 ALTERNATIVES

An analysis of the alternatives to increase the supply transfer capability and maintain load security in the region was undertaken by the IESO and is included in Section 7 (pages 44 to 47) of the IESO bulk planning report, which is provided as **Attachment 1** in **Exhibit H, Tab 1, Schedule 1**. Since the IESO's recommendation is specific on what is required to address the system need (i.e., reconstructing a section of the existing 230 kV transmission line with higher capacity conductor on new double-circuit towers), no other alternatives were considered. The need and recommended solution for the Project has been reaffirmed by the IESO as documented in **Exhibit B, Tab 3, Schedule 1, Attachment 1**.

2.0 TRANSMISSION LINE ALTERNATIVES

Conductor Size Alternative Analysis

Hydro One undertook an analysis of the conductor size alternatives that would: a) meet the requested increase in supply transfer capability and maintain load security in the area and, b) would also be the optimal conductor size and rating, based on the expected load scenario in terms of line losses. The conductor alternatives evaluated were:

1. Alternative 1 – 1433.6 kcmil ACSS/TW conductor
2. Alternative 2 – 1192.5 kcmil ACSR dual-conductor bundle

Analysis and Recommendations

All alternatives listed above address the supply transfer capability and load security needs of the Project and maintain the reliability and integrity of the transmission system. The following screening analysis considers the impact of line losses. The screening analysis summarized in Table 1 below was conducted in accordance with Hydro One's Transmission Line Loss Guideline.[1]

[1] As recently filed in proceeding EB-2023-0197, Exhibit I, Tab 2, Schedule 1, Attachment 1.

Table 1 - Screening Analysis

	Alternative #1 (1433.6 kcmil ACSS/TW)	**Alternative #2** (1192.5 kcmil ACSR dual-conductor bundle)
Net Capital Cost [2] ($M)	$15.373	$28.600
Losses at Peak Flow [3] (MW)	1.564	0.982
Losses at System Peak (MW)	0.062	0.039
Annual Revenue Costs ($M)	**$1.164**	**$2.166**
Annual Cost of Capital to Cover Losses ($M)	$0.010	$0.006
Annual Cost of Energy Losses ($M)	$0.729	$0.457
Annual Cost of Losses [4] ($M)	**$0.739**	**$0.464**
Total Annual Cost [5] ($M)	**$1.903**	**$2.630**

The screening analysis did not result in a change in alternative ranking. As such, no further study (i.e. NPV Sensitivity Analysis) of the alternatives was required in line with Hydro One's Transmission Line Loss Guideline. Based on the analysis above, Alternative #1 is more economical than Alternative #2, and thus Alternative #1 is selected as the preferred and recommended plan.

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[2] Net Capital Cost is the total cost net of removals; and was based on a project definition equivalent to a Class 3 (for Alternative 1) and Class 5 (for Alternative 2) under the AACE estimate classification system for all alternatives.
[3] Losses based on 2024 forecast flows.
[4] Annual Cost of Losses is the summation of Annual Cost of Energy Losses (i.e. MWHR losses multiplied by the energy price of $53.16/MWHR) and the Annual Cost of Capital to Cover Losses (i.e. MW losses multiplied by Capacity Price of $164,052/MW).
[5] Total Annual Cost is the summation of Annual Revenue Costs and Annual Cost of Losses.

QUANTITATIVE AND QUALITATIVE BENEFITS OF THE PROJECT

System benefits delivered by the Project are predominantly documented in the IESO bulk planning report found at **Exhibit H, Tab 1, Schedule 1, Attachment 1**. Further as described in **Exhibit B, Tab 3, Schedule 1**, the proposed facilities will increase the supply transfer capability in the area and maintain the reliability and integrity of the transmission system. The Project will also preserve the option to add a second circuit if/when it is required. The second circuit would further increase the transfer capability across the region, while maintaining load security.

The Project will utilize the existing transmission corridor lands thus minimizing overall impacts on natural and socio-economic environments, including agricultural land and wildlife habitat.

Hydro One also conducted an analysis of the conductor size alternatives to assess impacts with respect to transmission line losses. The analysis confirms that the 1433.6 kcmil ACSS/TW conductor is the most prudent conductor alternative to meet the needs of the Project. The results of that analysis are further discussed in **Exhibit B, Tab 5, Schedule 1**.

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APPORTIONING PROJECT COSTS AND RISKS

The estimated total capital cost of the M31W Reinforcement Project is $15.4M[1]. The breakdown of these costs is shown below in Table 1.

Table 1 - Total Capital Cost

	Estimated Cost ($000's)
Materials	$5,054
Labour	$3,785
Equipment Rental & Contractor Costs	$2,597
Sundry	$252
Contingencies	$1,610
Overhead [2]	$1,830
Allowance for Funds Used During Construction [3]	$195
Real Estate	$50
Total Capital Cost[4]	**$15,373**

The cost of the work provided in Table 1 above is predicated on the timing of the approval, design and construction activities provided in the Project Schedule at **Exhibit B, Tab 11, Schedule 1**. This cost estimate and similarly the Project Schedule, are based on a project definition equivalent to Class 3[5] under the AACE International (formerly the Association for the Advancement of Cost Engineering) estimate classification system[6]. The Project cost estimate was developed using internal cost estimate tools and techniques, and a risk management model for the contingency allowance.

[1] There will be an additional $778K of OMA removal costs associated with constructing this Project.
[2] Overhead Costs allocated to the Project are for corporate services costs. These costs are charged to capital projects through Hydro One's standard overhead capitalization rate (EB-2021-0110). As such they are considered "Indirect Overhead".
[3] AFUDC is calculated using the OEB's approved interest rate methodology (EB-2016-0160) to the forecast Project monthly cashflow and carrying forward closing balances from the preceding month.
[4] Total Capital Cost includes the line work ($15,340K) and station work ($33K) costs. The station work is for minimal protection setting changes and therefore is not represented in its own table.
[5] An estimate range of -20%/+30%
[6] As per 96r-18 Cost Estimate Classification System.

1.0 RISKS AND CONTINGENCIES

As with most projects, there are risks associated with estimating costs. Hydro One's cost estimate includes an allowance for contingencies in recognition of these risks. Hydro One follows an industry established best practices methodology in developing the contingency utilizing a risk management model that includes both a qualitative and a quantitative risk analysis of identified risks to the Project.

The Project risks that predominantly contribute to the total contingency suggested for this Project include the following:

- **Outage Constraints/Weather Delays**: Risk of securing required transmission system outages due to competing transmission system outages in the area or system constraints due to weather or environmental reasons. Outage delays/ cancellations or construction delays due to the weather could result in schedule delays or disruptions which ultimately may increase costs.
- **Subsurface Conditions**: Risk that the actual subsurface or environmental conditions may require additional mitigations that will have a cost impact and could delay or stop the project progress.
- **Procurement**: Risk to material lead times or material price increases that may cause delays or disruptions to the construction schedule and additional cost.

To mitigate these risks Hydro One has:

1. Factored outage planning in the development and scheduling phase of the Project. Crew allocation will be optimized to minimize any foreseeable delays due to outage or weather constraints.
2. Performed preliminary studies and testing to identify subsurface conditions in order to develop implementation plans to address the risk if encountered during construction.
3. Proactively initiated procurement of long lead materials in advance of the construction start date of the Project.

Cost contingencies that have not been included in the total contingency suggested for this project, due to the unlikelihood or uncertainty of occurrence, include:

- Labour disputes;
- Safety or environmental incidents;
- Significant changes in costs and/or availability of materials outside the control of Hydro One since the estimate preparation; and
- Any other unforeseen and potentially significant event/occurrence.

2.0 COSTS OF COMPARABLE PROJECTS - LINES

The OEB Filing Requirements for *Electricity Transmission Applications, Chapter 4*, requires the Applicant to provide information about a cost comparable project constructed by the Applicant. Table 2 compares the line cost of the Project with three most recent comparable projects.

- **Barrie Area Transmission Upgrade Project**: Upgrade of two existing 115 kV single-circuit wood pole transmission lines (E3B and E4B) to construct a new 230 kV double-circuit transmission line between Essa TS and Barrie TS (approximately 9 km) to address aging infrastructure and provide supply capacity in the Barrie/Innisfil areas. The new 230 kV double-circuit transmission line was constructed utilizing steel lattice tower structures. Leave to construct approval for this project was provided under OEB docket EB-2018-0117.
- **Guelph Area Transmission Reinforcement Project**: Upgrade of an existing 115 kV double-circuit wood pole transmission line (B5G/B6G) between CGE Junction and Campbell TS to construct a new 230 kV double-circuit transmission line (approximately 5 km) to reinforce the electricity supply and minimize the impact of major transmission outages on customers in the area. The new 230 kV double-circuit transmission line (D6V/D7V) was constructed utilizing a combination of steel lattice towers and steel pole structures. Leave to construct approval for this project was provided under OEB docket EB-2013-0053.
- **Woodstock Area Transmission Reinforcement Project**: Upgrade of an existing 115 kV double-circuit transmission line (W7W/W12W) to construct a new 230 kV double circuit transmission line between Ingersoll and Woodstock (approximately

13.6 km) to address capacity needs in the Woodstock Area. The new 230 kV double-circuit transmission line was connected to the existing 230 kV double-circuit transmission line (M32W/M31W) at Ingersoll TS and replaced approximately 12 km of the existing 115 kV ROW from Ingersoll TS to the new Karn TS and extended from Karn TS to Woodstock TS along the existing ROW. Leave to construct approval for this project was provided under OEB docket EB-2007-0027.

These projects were selected as reasonable comparables because they are all 230 kV transmission lines utilizing mainly double-circuit lattice structures and have similar line lengths. Both the Woodstock Area Transmission Reinforcement and Guelph Area Transmission Reinforcement projects are also similarly situated geographically in Southwestern Ontario area; and the Barrie Area Transmission Upgrade although located in Central Ontario is located in a mostly rural surrounding similar to the proposed Project.

For the purposes of the comparison, Hydro One has excluded costs associated with the stringing of the second 230 kV circuit on the double-circuit tower structures, and the temporary line bypass arrangements from the comparable projects. These costs have been excluded since they were project-specific requirements.

Hydro One has also excluded the real estate costs from all projects because these are project-specific costs and not comparable across projects. In the case of the proposed Project, no new permanent land rights are required unlike the other comparable projects.

Furthermore, to account for any variances in the unadjusted per km cost driven by the timing differences in the in-service dates, Table 2 has been adjusted to show the comparable projects in 2027 dollars utilizing inflation values for future years consistent with the inflation parameters provided by the OEB.

When considering the adjusted comparable cost per km ratio for all other transmission line costs in Table 2, the comparable projects demonstrate that the estimate for the Project is consistent with the cost to complete comparable transmission line works and is reasonable.

Table 2 - Costs of Comparable Line Projects

Project	Barrie Area Transmission Upgrade (Line Cost)	Guelph Area Transmission Refurbishment Project (Line Cost)	Woodstock Area Transmission Reinforcement (Line Cost)	M31W Reinforcement (Line Cost)
Circuit Operating Designation(s)	E28/E29	D6V/D7V	M32W/M31W plus K12/K7	M31W
Voltage	230 kV	230 kV	230 kV	230 kV
Structure Type	Steel Lattice	Steel Lattice Steel Pole	Steel Lattice Steel Pole	Steel Lattice
Single or Double Circuit	Double	Double	Double	Double[7]
Conductor	1443.7 kcmil ACSR/TW	1192.5 kcmil ACSR	1443.7 kcmil ACSR/TW	1433.6 kcmil ACSS/TW
Location	Central Ontario	Southwest Ontario	Southwest Ontario	Southwest Ontario
Project Surroundings	Mostly Rural	Urban	Urban-Rural	Rural
In-Service Year	2023	2016	2012	2027
Estimate or Actual	Actual	Actual	Actual	Estimate
OEB-Approved Cost Estimate	$22.9M[8]	$27.5M[9]	$42.9M[10]	–
Total Cost	$34,280K	$23,485K	$35,600K	$15,340K
Less Adjustments:				
Second Circuit	*$891K*	*$600K*	*$675K*	*N/A*
Real Estate	*$1,670K*	*$1,187K*	*$500K*	*$50K[11]*
Temporary Line Bypass	*N/A*	*N/A*	*$4,300K*	*N/A*
Comparable Costs, before Escalation	*$31,719K*	*$21,698K*	*$30,125K*	*$15,290K*
Escalation Adjustment[12]	*$4,377K*	*$7,310K*	*$14,049K*	*N/A*
Total Adjusted Comparable Cost	*$36,096K*	*$29,008K*	*$44,174K*	*$15,290K*
Approximate Length	9 km	5 km	13.6 km	4 km
Unit Cost	**$4,011K/km**	**$5,802K/km**	**$3,248K/km**	**$3,823K/km**

[7] As noted in Exhibit B, Tab 2, Schedule 1, the IESO's recommendation is to rebuild the existing 230 kV single-circuit transmission line (M31W) with higher capacity conductor strung on new 230kV double-circuit towers capable of accommodating a second circuit in the future. An adjustment to the comparable project's costs has been made in Table 2 to reflect the stringing of only one circuit on the new 230 kV double-circuit towers.
[8] As per Section 92 leave to construct proceeding EB-2018-0117.
[9] As per Section 92 leave to construct proceeding EB-2013-0053.
[10] As per Section 92 leave to construct proceeding EB-2007-0027.
[11] These real estate costs pertain to the temporary access land rights required only, as no new permanent land rights are required for this Project, as outlined in Exhibit E, Tab 1, Schedule 1.
[12] Inflation adjustment factors used for comparator projects are consistent with the OEB's annual inflation parameters for electricity transmitters' rate applications.

3.0 COSTS OF COMPARABLE PROJECTS – STATIONS

The cost of the station work at Buchanan TS and Middleport TS includes only minor modifications to the 230 kV transmission line protection settings. This work represents less than 1% of the total Project cost and does not meet Hydro One’s materiality threshold. Consequently, the forecast estimate to deliver this component of the Project has not been compared relative to other projects to support the reasonableness of the station work cost estimate.

CONNECTION PROJECTS REQUIRING NETWORK REINFORCEMENT

This is not a connection project. Facilities being reconstructed as part of this Project are limited to those discussed in the details of the work being undertaken in **Exhibit C, Tab 1, Schedule 1**.

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TRANSMISSION RATE IMPACT ASSESSMENT

1.0 ECONOMIC FEASIBILITY

The Project costs will be included in the network pool for cost classification purposes and not allocated to any individual customer. See **Exhibit B, Tab 2, Schedule 1**, for information on the proposed work. No customer contribution is required for the Project.

A 25-year discounted cash flow analysis of the network pool work demonstrates that based on the estimated initial cost of $16.2 million[1], plus the assumed impact on the future capital cost allowance, Hydro One's corporate income tax and approximately $14.8 million annually of average incremental network revenue utilizing the 2025 UTR over a 25-year evaluation period, this Project will have a positive net present value of $108.5 million as seen in Tables 1 and 2.

2.0 COST RESPONSIBILITY

Network Pool

The Project will increase the supply transfer capability by 300MW to address electricity demand and maintain the reliability and integrity of the transmission system, as identified by the IESO[2].

The proposed reconstruction of a section of the existing 230 kV transmission line (M31W) from Buchanan TS to Old Victoria Road Junction is to be included in the Network Pool as both terminal stations, Buchanan TS and Middleport TS, are network stations and the proposed Project addresses the above stated IESO-identified bulk system needs. No customer capital contribution is required, consistent with the provisions in Section 6.3.5 of the TSC.

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[1] Initial network costs of $16.2 million include $15.4 million of up-front capital costs plus $0.8 million cost of removals.
[2] Exhibit H, Tab 1, Schedule 1, Attachment 1.

3.0 RATE IMPACT ASSESSMENT

The analysis of the rate impacts has been carried out on the basis of Hydro One's transmission revenue requirement for the year 2026, and the 2025 approved Ontario Transmission Rate Schedules. The Network pool revenue requirements would be affected by the Project based on the project cost allocation.

Network Pool

Based on the estimated initial cost of $16.2 million and the associated network pool incremental cash flows, there will be a change in the network pool revenue requirement once the Project's impacts are reflected in the transmission rate base at the projected in-service date of February 12, 2027. The 2025 OEB approved rate of $6.37 per kW/month gradually decreases over the economic horizon period becoming $6.28 per kW/month by year 18. The detailed analysis illustrating the calculation of the incremental network revenue and rate impact is provided in Tables 3 and 4 below.

Impact on Typical Residential Customer

Based on the load forecast, initial capital costs and ongoing maintenance costs, adding the costs of the required facilities to the network pool will cause a $0.14 per month decrease in a typical residential customer's bills under the RPP. The table below shows this result for a typical residential customer who is under the RPP, utilizing the maximum impact by rate pool, regardless of year.

Rate Impact on Typical Residential Customer Bill

A. Typical monthly bill	$153.95 per month
B. Transmission component of monthly bill	$17.27 per month
C. Line Connection Pool share of Transmission component	$1.6 per month
D. Transformation Connection Pool share of Transmission component	$5.42 per month
E. Network Connection Pool share of Transmission component	$10.25 per month
F. Impact on Line Connection Pool Provincial Uniform Rates	0.00%
G. Impact on Transformation Connection Pool Provincial Uniform Rates	0.00%
H. Impact on Network Connection Pool Provincial Uniform Rates	-1.41%
I. Increase/(Decrease) in Transmission costs for typical monthly bill (C x F + D x G + E x H)	-$0.14 per month or -$1.74 per year
J. Net increase/(decrease) on typical residential customer bill (I / A)	-0.09%

Table 1 - Net Present Value, Network Pool page 1

Date:	16-Dec-25
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

Facility Name:	M31W Reconductor Project
Description:	M31W Reinforcement: Buchanan TS X Old Victoria Rd JCT
Customer:	

		In-Service Date	<-------	Project year ended - annualized from In-Service Date	-------->									
Month		Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12
Year		2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
		0	1	2	3	4	5	6	7	8	9	10	11	12
Revenue & Expense Forecast														
Load Forecast (MW)			67.0	89.0	89.0	88.9	88.2	90.3	94.3	99.2	113.3	129.6	149.0	172.6
Load adjustments (MW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
			67.0	89.0	89.0	88.9	88.2	90.3	94.3	99.2	113.3	129.6	149.0	172.6
Tariff Applied ($/kW/Month)			6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
Incremental Revenue - $M			5.1	6.8	6.8	6.8	6.7	6.9	7.2	7.6	8.7	9.9	11.4	13.2
Removal Costs - $M		(0.8)												
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M			(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		(0.8)	5.1	6.8	6.8	6.8	6.7	6.9	7.2	7.5	8.6	9.9	11.3	13.2
Income Taxes		0.2	(1.2)	(1.5)	(1.5)	(1.5)	(1.5)	(1.6)	(1.7)	(1.8)	(2.1)	(2.5)	(2.9)	(3.3)
Operating Cash Flow (after taxes) - $M		(0.6)	3.9	5.3	5.3	5.2	5.2	5.3	5.5	5.7	6.5	7.4	8.5	9.8
	Cumulative PV @ 5.65%													
PV Operating Cash Flow (after taxes) - $M (A)	**123.8**	**(0.6)**	**3.8**	**4.9**	**4.6**	**4.3**	**4.0**	**3.9**	**3.8**	**3.8**	**4.1**	**4.4**	**4.8**	**5.2**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC		(13.3)												
- Overheads		(1.8)												
- AFUDC		(0.2)												
Total upfront capital expenditures		**(15.4)**												
On-going capital expenditures			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures		0.0												
Total capital expenditures - $M		**(15.4)**												
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M		**0.1**												
PV Working Capital - $M		**0.0**												
PV Capital (after taxes) - $M (B)	**(15.3)**	**(15.3)**												
Cumulative PV Cash Flow (after taxes) - $M (A) + (B)	**108.5**	**(15.9)**	**(12.1)**	**(7.2)**	**(2.6)**	**1.7**	**5.7**	**9.6**	**13.4**	**17.2**	**21.3**	**25.7**	**30.5**	**35.7**

Discounted Cash Flow Summary

Economic Study Horizon - Years: **25**

Discount Rate - % **5.65%**

		Before Cont $M
PV Incremental Revenue		166.7
PV OM&A Costs		(0.8)
PV Municipal Tax		(0.7)
PV Income Taxes		(43.8)
PV CCA Tax Shield		2.4
PV Capital - Upfront	(15.4)	
Add: PV **Capital Contribution**	**0.0**	(15.4)
PV Capital - On-going		0.0
PV Working Capital		0.0
PV Surplus / (Shortfall)		**108.5**
Profitability Index*		**8.1**

Notes:
*PV of total cash flow, excluding net capital expenditure & on-going capital & proceeds on disposal / PV of net capital expenditure & on-going capital & proceeds on disposal

Other Assumptions

In-Service Date:	12-Feb-27
Payback Year:	2031
No. of years required for payback:	4

Table 2 - Net Present Value, Network Pool, page 2

Date:	16-Dec-25
Project #	

SUMMARY OF CONTRIBUTION CALCULATIONS
Network Pool - Estimated cost

Facility Name:	M31W Reconductor Project
Description:	M31W Reinforcement: Buchanan TS X Old Victoria Rd JCT
Customer:	

<------- Project year ended - annualized from In-Service Date -------->

		2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
	Month	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12	Feb-12
	Year	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**	**2049**	**2050**	**2051**	**2052**
		13	*14*	*15*	*16*	*17*	*18*	*19*	*20*	*21*	*22*	*23*	*24*	*25*
Revenue & Expense Forecast														
Load Forecast (MW)		192.1	216.7	236.8	257.8	278.9	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Load adjustments (MW)		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
		192.1	216.7	236.8	257.8	278.9	300.0	300.0	300.0	300.0	300.0	300.0	300.0	300.0
Tariff Applied ($/kW/Month)		6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37	6.37
Incremental Revenue - $M		14.7	16.6	18.1	19.7	21.3	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
Removal Costs - $M														
On-going OM&A Costs - $M		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Municipal Tax - $M		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)
Net Revenue/(Costs) before taxes - $M		14.6	16.5	18.1	19.7	21.3	22.9	22.9	22.9	22.9	22.9	22.9	22.9	22.9
Income Taxes		(3.8)	(4.3)	(4.7)	(5.1)	(5.6)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)	(6.0)
Operating Cash Flow (after taxes) - $M		10.9	12.3	13.4	14.6	15.7	16.9	16.9	16.9	16.9	16.9	16.9	16.9	16.9
PV Operating Cash Flow (after taxes) - $M	**(A)**	**5.5**	**5.8**	**6.0**	**6.2**	**6.3**	**6.5**	**6.1**	**5.8**	**5.5**	**5.2**	**4.9**	**4.6**	**4.4**
Capital Expenditures - $M														
Upfront - capital cost before overheads & AFUDC														
- Overheads														
- AFUDC														
Total upfront capital expenditures														
On-going capital expenditures		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PV On-going capital expenditures														
Total capital expenditures - $M														
Capital Expenditures - $M														
PV CCA Residual Tax Shield - $M														
PV Working Capital - $M														
PV Capital (after taxes) - $M	**(B)**													
Cumulative PV Cash Flow (after taxes) - $M	**(A) + (B)**	**41.1**	**47.0**	**53.0**	**59.2**	**65.5**	**72.0**	**78.1**	**83.9**	**89.4**	**94.5**	**99.4**	**104.1**	**108.5**

Table 3 - Revenue Requirement and Network Pool Rate Impact, page 1

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

M31W Reconductor Project		Project YE 12-Feb 2028	12-Feb 2029	12-Feb 2030	12-Feb 2031	12-Feb 2032	12-Feb 2033	12-Feb 2034	12-Feb 2035	12-Feb 2036	12-Feb 2037	12-Feb 2038	12-Feb 2039
Calculation of Incremental Revenue Requirement ($000)		1	2	3	4	5	6	7	8	9	10	11	12
In-service date	12-Feb-27												
Capital Cost	15,373												
Less: Capital Contribution Required	-												
Net Project Capital Cost	15,373												
Average Rate Base		7,533	14,912	14,604	14,297	13,989	13,682	13,375	13,067	12,760	12,452	12,145	11,837
Incremental OM&A Costs		0	0	0	0	0	0	0	0	0	0	0	0
Grants in Lieu of Municipal tax		51	51	51	51	51	51	51	51	51	51	51	51
Depreciation		307	307	307	307	307	307	307	307	307	307	307	307
Interest and Return on Rate Base		478	946	926	907	887	868	848	829	809	790	770	751
Income Tax Provision		(9)	(114)	(84)	(56)	(32)	(9)	11	29	46	60	74	86
REVENUE REQUIREMENT PRE-TAX		**827**	**1,190**	**1,201**	**1,208**	**1,214**	**1,216**	**1,217**	**1,216**	**1,213**	**1,208**	**1,202**	**1,195**
Incremental Revenue		5,125	6,808	6,808	6,801	6,744	6,910	7,216	7,586	8,669	9,912	11,397	13,201
SUFFICIENCY/(DEFICIENCY)		**4,298**	**5,617**	**5,607**	**5,593**	**5,531**	**5,693**	**5,999**	**6,370**	**7,456**	**8,704**	**10,195**	**12,007**
	Base Year												
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,497,314	1,498,141	1,498,504	1,498,515	1,498,522	1,498,528	1,498,530	1,498,531	1,498,530	1,498,527	1,498,522	1,498,516	1,498,509
Network MW	234,895	235,699	235,963	235,963	235,962	235,953	235,979	236,027	236,085	236,255	236,450	236,683	236,966
Network Pool Rate ($/kw/month)	6.37	6.36	6.35	6.35	6.35	6.35	6.35	6.35	6.35	6.34	6.34	6.33	6.32
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		-0.01	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.02	-0.03	-0.03	-0.04	-0.05
RATE IMPACT relative to base year		**-0.16%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.31%**	**-0.47%**	**-0.47%**	**-0.63%**	**-0.78%**

Table 4 - Revenue Requirement and Network Pool Rate Impact, page 2

Revenue Requirement and Network Pool Rate Impact **(Before Capital Contribution)**

M31W Reconductor Project		12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb	12-Feb
		2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Calculation of Incremental Revenue Requirement ($000)		13	14	15	16	17	18	19	20	21	22	23	24	25
In-service date	12-Feb-27													
Capital Cost	15,373													
Less: Capital Contribution Required	-													
Net Project Capital Cost	15,373													
Average Rate Base		11,530	11,222	10,915	10,607	10,300	9,992	9,685	9,378	9,070	8,763	8,455	8,148	7,840
Incremental OM&A Costs		0	0	0	0	0	0	0	0	0	0	0	0	0
Grants in Lieu of Municipal tax		51	51	51	51	51	51	51	51	51	51	51	51	51
Depreciation		307	307	307	307	307	307	307	307	307	307	307	307	307
Interest and Return on Rate Base		731	712	692	673	653	634	614	595	575	556	536	517	497
Income Tax Provision		96	106	114	122	128	134	138	143	146	149	151	153	154
REVENUE REQUIREMENT PRE-TAX		**1,186**	**1,176**	**1,165**	**1,152**	**1,139**	**1,125**	**1,111**	**1,095**	**1,079**	**1,063**	**1,045**	**1,028**	**1,009**
Incremental Revenue		14,693	16,573	18,110	19,716	21,335	22,948	22,948	22,948	22,948	22,948	22,948	22,948	22,948
SUFFICIENCY/(DEFICIENCY)		**13,507**	**15,398**	**16,945**	**18,564**	**20,196**	**21,822**	**21,837**	**21,852**	**21,869**	**21,885**	**21,902**	**21,920**	**21,938**
	Base Year													
Network Pool Revenue Requirement including sufficiency/(deficiency)	1,497,314	1,498,500	1,498,490	1,498,479	1,498,466	1,498,453	1,498,439	1,498,425	1,498,409	1,498,393	1,498,377	1,498,359	1,498,342	1,498,323
Network MW	234,895	237,200	237,495	237,736	237,988	238,242	238,495	238,495	238,495	238,495	238,495	238,495	238,495	238,495
Network Pool Rate ($/kw/month)	6.37	6.32	6.31	6.30	6.30	6.29	6.28	6.28	6.28	6.28	6.28	6.28	6.28	6.28
Increase/(Decrease) in Network Pool Rate ($/kw/month), relative to base year		-0.05	-0.06	-0.07	-0.07	-0.08	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09	-0.09
RATE IMPACT relative to base year		**-0.78%**	**-0.94%**	**-1.10%**	**-1.10%**	**-1.26%**	**-1.41%**	**-1.41%**	**-1.41%**	**-1.41%**	**-1.41%**	**-1.41%**	**-1.41%**	**-1.41%**

Table 5 - DCF Assumptions

Hydro One Networks -- Transmission Connection Economic Evaluation Model
2025 Parameters and Assumptions

Transmission rates are based on current OEB-approved uniform provincial transmission rates.

Monthly Rate ($ per kW)	
Network	**6.37**
Transformation	**3.39**
Line	**1.00**

Grants in lieu of Municipal tax (% of up-front capital expenditure, a proxy for property value):		**0.33%**	Based on Transmission system average
Income taxes:			
Basic Federal Tax Rate - % of taxable income:	2025	**15.00%**	Current rate
Ontario corporation income tax - % of taxable income:	2025	**11.50%**	Current rate
Capital Cost Allowance Rate:			
Class 47 costs	2025	**8%**	Current rate
Easement rights	2025	**5%**	
Decision Support defined costs (2)	2025	**0%**	
Decision Support defined costs (3)	2025	**0%**	
After-tax Discount rate:		**5.65%**	Based on OEB-approved ROE of 9.36% on common equity and 4.79% on short-term debt, 4.3% forecast cost of long-term debt and 40/60 equity/debt split, and current enacted income tax rate of 26.5%

REVENUE REQUIREMENT INFORMATION AND DEFERRAL ACCOUNT REQUESTS

1.0 REVENUE REQUIREMENT AND TRANSMISSION SYSTEM PLAN INFORMATION

The need for the Project was not identified in the TSP submitted as part of Hydro One's most recent 2023-27 transmission revenue requirement application (EB-2021-0110)[1]. The Project is a result of a newly emergent bulk system need that was subsequently recognized through the Central West bulk planning process. The Central West bulk planning process commenced with an initial engagement session on August 16, 2023, and concluded with the release of the Central West Bulk Plan Report on April 18, 2024. The IESO formally recommended the need for the Project in this bulk plan report, which is provided in **Exhibit H, Tab 1, Schedule 1, Attachment 1**. All of these bulk planning process activities occurred after Hydro One's most recent revenue requirement application had concluded.

2.0 DEFERRAL ACCOUNT REQUEST INFORMATION

There are no new deferral or variance account requests being made as part of this Application.

[1] OEB Decision and Order, dated November 29, 2022.

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PROJECT SCHEDULE

TASK	START	FINISH
Section 92 Approval[1]	Jan-2026	Jun-2026
Receipt of Other Key Permits and Approvals	Jan-2026	Jun-2026
Voluntary Temporary Land Rights Acquisition[2]	Dec-2025	Apr-2026
Detailed Engineering	Apr-2025	Mar-2026
Procurement	Jan-2026	Oct-2026
Construction	Jul-2026	Feb-2027
Commissioning	Feb-2027	Feb-2027
In Service	N/A	**Feb-2027**
Site Remediation Completion	N/A	May-2027

The table above outlines the forecast schedule for the Project and has been predicated on Hydro One successfully securing leave to construct approval by June 2026. There are no new permanent land rights required as the existing transmission corridor will provide sufficient width for the proposed Project; however, Hydro One will require temporary off-corridor access to facilitate entry for the construction of the transmission facilities. Construction is set to commence in July 2026 and the cost evidence provided in **Exhibit B, Tab 7, Schedule 1** is underpinned by this schedule**.** As identified in **Exhibit B, Tab 7, Schedule 1,** delays in regulatory approvals beyond those contemplated in the project schedule documented above could materially impact the cost of the Project. Contingency

[1] This review time is predicated on the OEB Performance Standards for processing Leave to Construct Applications and assumes a written hearing review of this Application. However, Hydro One is hopeful that regulatory efficiencies can be obtained in the review of this Application and that this Application will be disposed of without a hearing for the reasons articulated in Exhibit B, Tab 1, Schedule 1.

[2] Completion timing of temporary off-corridor access is dependent upon property owner-specific negotiations.

has been carried on the Project to account for minor deviations to this schedule, however, material delays in securing approvals could have significant impacts that have not been carried in contingency. Project timelines have been based on recent OEB processing timelines and take into consideration the OEB's Performance Standards for Processing Leave to Construct Applications.

DESCRIPTIONS OF THE PHYSICAL DESIGN

1.0 ROUTE DESCRIPTION

The 230 kV transmission corridor travelling east of Buchanan TS is located in Southwestern Ontario in the City of London. This 230 kV transmission corridor consists of three 230 kV transmission lines (M31W, M32W, M33W) and is a critical transmission corridor connecting Buchanan TS and Middleport TS. The proposed Project is to reconstruct a 4 km section of the existing 230 kV single-circuit transmission line (M31W) between Buchanan TS and Old Victoria Road Junction. The 230 kV transmission line will be rebuilt with new tower structures and higher capacity conductor within the existing 70 to 120 meter wide ROW.

1.1 ROUTE DETAILS

i. The Project route starts at Buchanan TS located at the northwest corner of Highway 401 and Highbury Avenue in London, ON.
ii. The line exits the station and heads east for approximately 4 km along the existing 230 kV transmission corridor towards Old Victoria Road Junction. This junction is located just west of Old Victoria Road in London, ON.
iii. At Old Victoria Road Junction the new line section from Buchanan TS will terminate at the new structure 292 and connect to the existing line section that continues from structure 292 towards Middleport TS.

A map showing the general route of the Project is provided as **Attachment 1** of **Exhibit B, Tab 2, Schedule 1**.

2.0 LINE DESCRIPTION

The proposed 230 kV transmission line will have one (1) circuit comprised of one 1433.6 kcmil ACSS/TW MA5 "*Merrimack*" conductor per phase, two 19#8 Alumoweld overhead shieldwires and will primarily be supported on self-supporting double-circuit lattice towers. Further, the transmission line will have the following attributes:

i. The line will have a continuous ampacity of 1787A and a long-term emergency ampacity of 2028A (summer ambient 35°C);
ii. Glass type insulators will be used for both suspension and tension applications in accordance with Hydro One standards;
iii. Stockbridge-type vibration dampers to dampen the conductor and overhead shieldwire in accordance with Hydro One standard, based on the final line configuration and per the manufacturer's design;
iv. Typical structure foundations will be concrete auger footings; and
v. The line will make use of twelve (12) X10S-R self-support lattice suspension tower structures with nominal spans of approximately 273 meters (refer to Figure 1); and two (2) X10H-R heavy anchor and one (1) X10M-R medium anchor tower structures (refer to Figure 2 and 3 respectively). There will also be structural reinforcement of the first dead end structure outside of Buchanan TS to accommodate the higher design loads of the new conductor.

Consistent with the IESO's recommendation in the IESO's Central-West Bulk Plan report, provided as **Attachment 1 of Exhibit H, Tab 1, Schedule 1**, the reconstruction of the 230 kV single-circuit transmission line on double-circuit towers preserves the option for a future 230 kV circuit to continue to supply the area when the load growth materializes. Currently the need for an additional 230 kV circuit has not been identified.

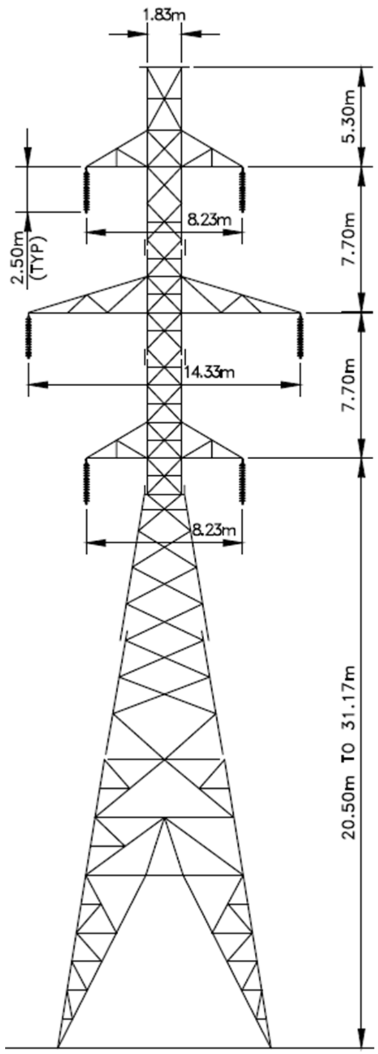

Figure 1: 230kV Double-Circuit Suspension Tower Structure (Type: X10S-R)

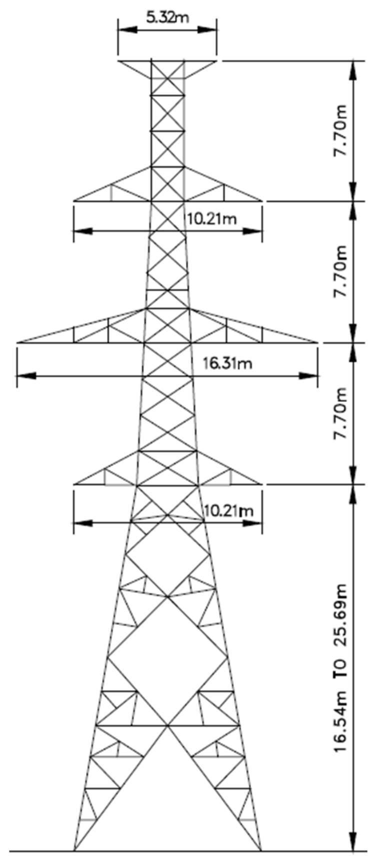

Figure 2: 230kV Double-Circuit Heavy Anchor Tower Structure (Type: X10H-R)

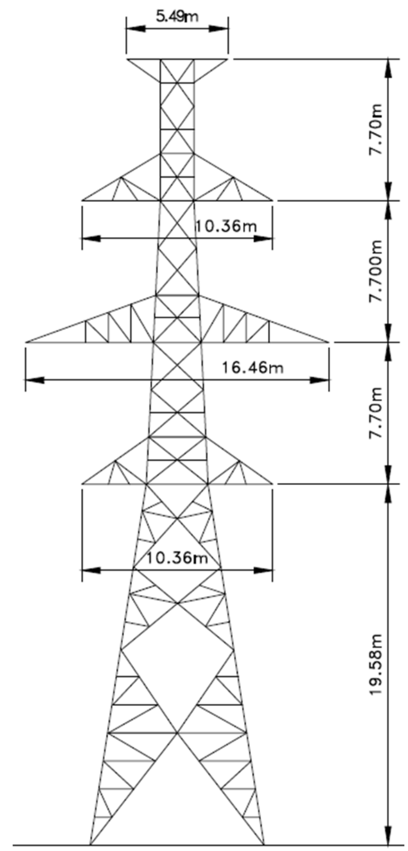

Figure 3: 230kV Double-Circuit Medium Anchor Tower Structure (Type: X10M-R)

3.0 LINE REMOVAL

As aforementioned, the Project will involve reconstruction of an existing section of the 230 kV single-circuit transmission line (M31W) within an existing transmission corridor. The existing section of the transmission line will be removed between Buchanan TS and Old Victoria Road Junction; including 12 transmission structures (structures 292 to 303), conductor and associated components.

4.0 STATION WORK

In conjunction with the line facilities work described above, the Project may require minor station related work at both Buchanan TS and Middleport TS, specifically modifications to the 230 kV transmission line protection settings. Fault studies will be undertaken to verify the distance protection setting values and modifications made as required.

OPERATIONAL DETAILS

The proposed facilities are part of the Central-West bulk transmission system and are required to increase supply transfer capability and maintain the reliability and integrity of the transmission system. The proposed Project involves reconstruction of a 4 km section of the existing 230 kV transmission line (M31W), from Buchanan TS to Old Victoria Road Junction, utilizing higher capacity conductor and new tower structures within the existing ROW, as aforementioned in the Application. Minor modifications to the 230 kV transmission line protection settings at Hydro One's terminal stations, Buchanan TS and Middleport TS, may be required. Operation of the proposed facilities will continue to be in accordance with the procedures of Hydro One's ISOC as directed by the IESO.

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LAND MATTERS

1.0 DESCRIPTION OF LAND RIGHTS

As referenced in the Application, Hydro One is proposing to reconstruct a 4 km section of an existing 230 kV single-circuit transmission line (M31W) between Buchanan TS and Old Victoria Road Junction, located in the City of London. The width of the existing ROW varies from 70 to 120 meters, and will provide sufficient width for the proposed work. Consequently, no new permanent property rights acquisitions are contemplated by this Project as of the filing of this Application.

The existing transmission corridor is exclusively situated on Bill 58 lands, lands owned by the Province of Ontario over which Hydro One holds a statutory easement, except for, where necessary, crossing perpendicularly over public roads. In those instances, Hydro One will stay within public road allowances and exercise legislated occupation rights pursuant to section 41 of the *Electricity Act*. The proposed transmission Project, therefore, is not expected to have a material impact on the rights of adjacent properties and will rely on existing occupational rights that currently exist to effectuate construction. Utilizing existing infrastructure and facilities is consistent with the *Ministry of Municipal Affairs and Housing Provincial Policy Statement, 2024*[1] under the *Planning Act,* more specifically by utilizing existing utility ROW where achievable.

The relative land ownership type proportions specific to the properties affected are as follows:

Table 1 - Summary of Property Types and Size

Land Ownership Type	Area (Hectares)	Proportion of Route (%)
Bill 58 (Infrastructure Ontario) Lands	37.66	96.9%
Road Allowance	1.19	3.1%

[1] Sections 3.3.4 and 3.3.5 of the Provincial Policy Statement (2024): https://www.ontario.ca/page/provincial-planning-statement-2024

The reconstructed transmission line will be all above ground and will, for all sections, be constructed to account for the routes' topography and associated land profiles, ensuring the Project meets Hydro One's minimum line clearances designed for the Project's selected conductor sizing.

2.0 MAPS OF THE PROJECT AREA

At **Exhibit B, Tab 2, Schedule 1, Attachment 1**, Hydro One has provided a map with the intention it be used as the Application's *Notice Map* should the OEB determine that a hearing is required. **Attachment 1 of this Schedule** provides a more detailed route map that illustrates, as appropriate, properties along line route sections with PIN numbers[2] of the land over, under, on or adjacent to which the line runs. As illustrated therein, and detailed in this Schedule, the route runs adjacent to properties but no permanent property rights from those adjacent properties are required to deliver the Project and thus these lands will not be materially affected by the Project.

3.0 DESCRIPTION OF NEW LAND RIGHTS REQUIRED

As aforementioned, no new permanent land rights are required. The Project will be constructed within the existing transmission corridor which is exclusively situated on Bill 58 lands, lands owned by the Province of Ontario over which Hydro One holds a statutory easement, except for, where necessary, crossing perpendicularly over public roads.

However, temporary access land rights for access roads, temporary work headquarters, and/or laydown/material areas may be required across private lands to facilitate construction of the Project. These rights will be negotiated and acquired as and when needed. The following land rights agreements are or may be required on affected properties:

- Off Corridor Access;
- Damage Claim Agreement/Waiver.

[2] PIN numbers have been provided and can be reasonably utilized to validate lot and concession numbers as may be necessary for the purposes of this proceeding.

Where crossings of public roads and highways are contemplated and indicated in **Attachment 1 of this Schedule**, Hydro One will rely on the land rights afforded by section 41 of the *Electricity Act* (where applicable). Hydro One will notify and work with impacted road authorities, including municipalities and ministries, and obtain all required permits and/or agreements, including where agreements are required for the placement of infrastructure per section 41(9) of the *Electricity Act*. Hydro One expects that permits/agreements for all required crossings will be acquired either prior to the start of construction or on an as needed basis.

4.0 EARLY ACCESS TO LAND

The corridor is exclusively situated on Bill 58 lands. As a result, no early access to land is necessary for the purposes of this filing.

5.0 LAND ACQUISITION PROCESS

There will be no permanent acquisition of new land rights required to deliver the Project therefore this section of evidence is not applicable to this filing.

6.0 LAND-RELATED FORMS

Attachments 2 and 3 of this Schedule contain the agreements that Hydro One proposes to utilize to obtain any necessary temporary access land rights for the Project and related Project activities. These agreements are consistent with forms previously approved and do not include any substantive changes. Table 2 below indicates the proceeding where the form of these agreements were previously approved.

Table 2 - Forms of Agreement Remaining Unchanged

Form of Agreement	Attachment in this Schedule	Previous OEB Docket
Off Corridor Access	2	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 10
Damage Claim Agreement/Waiver	3	EB-2024-0155, Exhibit E, Tab 1, Schedule 1, Attachment 12

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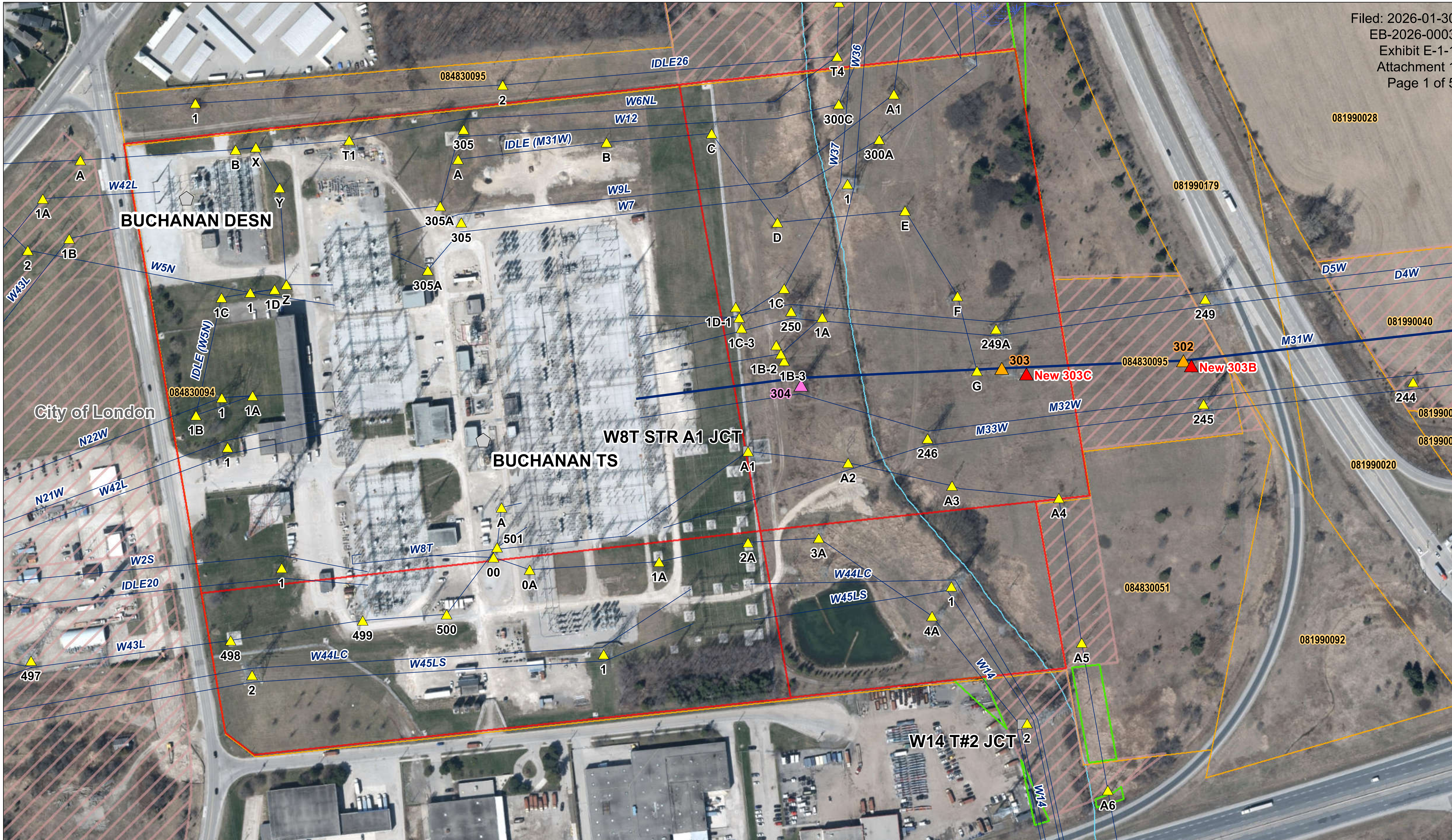
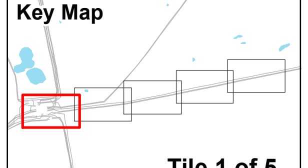


Key Map



Tile 1 of 5

- Proposed New Structures
- Existing Structures Proposed for Reinforcement
- Existing Structures Proposed for Removal
- Existing Structures
- Station
- Junction
- M31W Tx Line
- Other Tx Line
- Railway
- Hydro One Owned Lands
- Hydro One Existing Easement
- Bill 58
- Property Boundary
- Watercourse
- Wetlands
- Waterbody
- Municipal Boundary

M31W Reinforcement Project
General Area Map

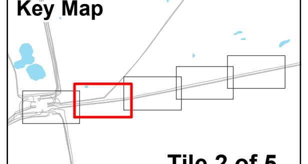
1:2,500

0 50 100 m

Produced By: Hydro One Networks Inc., GIS Services
Date: Oct 31, 2025
Map25-049_M31W_Reinforcement_Project_London_TileMap_PIN

Produced By: Hydro One Networks Inc., GIS Services
Date: Oct 31, 2025
Map25-049_M31W_Reinforcement_Project_London_TileMap_PIN

Key Map



Tile 2 of 5

- Proposed New Structures
- Existing Structures Proposed for Reinforcement
- Existing Structures Proposed for Removal
- Existing Structures
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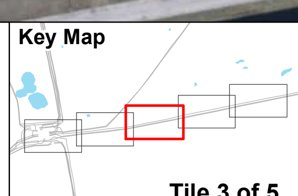
M31W Reinforcement Project
General Area Map

1:2,500 0 50 100 m

Produced By: Hydro One Networks Inc., GIS Services
Date: Oct 31, 2025
Map25-049_M31W_Reinforcement_Project_London_TileMap_PIN



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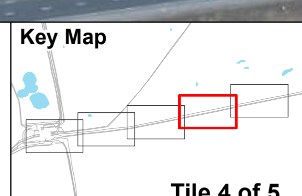
- Waterbody
- Municipal Boundary

M31W Reinforcement Project
General Area Map

1:2,500 0 50 100 m

Produced By: Hydro One Networks Inc., GIS Services
Date: Oct 31, 2025
Map25-049_M31W_Reinforcement_Project_London_TileMap_PIN

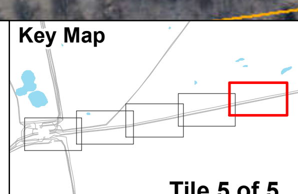


Proposed New Structures
Existing Structures Proposed for Reinforcement
Existing Structures Proposed for Removal
Existing Structures
Station
Junction
M31W Tx Line
Other Tx Line
Railway
Hydro One Owned Lands
Hydro One Existing Easement
Bill 58
Property Boundary
Watercourse
Wetlands
Waterbody
Municipal Boundary

M31W Reinforcement Project
General Area Map

1:2,500
0 50 100 m

Produced By: Hydro One Networks Inc., GIS Services
Date: Oct 31, 2025
Map25-049_M31W_Reinforcement_Project_London_TileMap_PIN



- Proposed New Structures
- Existing Structures Proposed for Reinforcement
- Existing Structures Proposed for Removal
- Existing Structures
- Station
- Junction
- M31W Tx Line
- Other Tx Line
- Railway
- Hydro One Owned Lands
- Hydro One Existing Easement
- Bill 58
- Property Boundary
- Watercourse
- Wetlands
- Waterbody
- Municipal Boundary

M31W Reinforcement Project
General Area Map

1:2,500 0 50 100 m

THIS AGREEMENT made in duplicate the _________day of _______________, 202_

Between:

XXX

(hereinafter referred to as the "Grantor")
OF THE FIRST PART

--- and ---

HYDRO ONE NETWORKS INC.

(hereinafter referred to as "HONI")
OF THE SECOND PART

WHEREAS the Grantor is the owner in fee simple and in possession of certain lands legally described as **XXX (the "Lands").**

WHEREAS The Grantor has entered into a Temporary Access Agreement with HONI on a portion of the Lands highlighted in green in Schedule "A" (the "Access Lands"). HONI will be utilizing a portion of the Lands as a means of off-corridor access highlighted in blue in Schedule "A" ("Off-Corridor Access Lands").

WHEREAS the Owner is agreeable in allowing HONI to enter onto the Lands to use the Off-Corridor Access Lands in order to commence activities which shall include necessary real estate, environmental and engineering studies and testing including but not limited to borehole testing, archaeological studies, soil assessments, property appraisals and surveys in, on or below the Lands subject to the terms and conditions contained herein (the "Activities").

NOW THEREFORE THIS AGREEMENT WITNESSES THAT in consideration of the lump sum of **$XXX.00** now paid by HONI to the Owner, and the respective covenants and agreements of the parties hereinafter contained and other valuable consideration, the receipt and sufficiency of which are hereby acknowledged by the parties hereto, the parties hereto agree as follows:

1. The Grantor hereby grants to HONI the right to enter upon the Lands for the purpose Off-Corridor Access Lands.

2. The Grantor hereby grants to HONI, as of the date this Agreement, (i) the right to enter upon and exit from, and to pass and repass at any and all times in, over, along, upon, across, through and under the Off-Corridor Access Lands as may be reasonably necessary, at all reasonable times, for HONI and its respective officers, employees, workers, permittees, servants, agents, contractors and subcontractors, with or without vehicles, supplies, machinery, plant, material and equipment for the purpose of the Activities, subject to payment of compensation for damages including payment for crops caused thereby. HONI agrees that it shall take all reasonable care while undertaking the Activities.

3. The term of this Agreement and the permission granted herein shall be two (2) years from the date written above (the "Term"). HONI may, in its sole discretion, and upon 10 days notice to the Grantor, extend the Term for an additional length of time, which shall be negotiated between the parties.

4. Upon the expiry of the Term or any extension thereof, HONI shall repair any physical damage to the Off-Corridor Access Lands and/or Lands resulting from HONI's use of the Access Lands and the permission granted herein; and, shall restore the Access Lands to its original condition so far as possible and practicable.

5. All agents, representatives, officers, directors, employees and contractors and property of HONI located at any time on the Off-Corridor Access Lands shall be at the sole risk of HONI and the Grantor shall not be liable for any loss or damage or injury (including loss of life) to them or it however occurring except and to the extent to which such loss, damage or injury is caused by the negligence or willful misconduct of the Grantor.

6. HONI agrees that it shall indemnify and save harmless the Grantor from and against all claims, demands, costs, damages, expenses and liabilities (collectively the “Costs”) whatsoever arising out of HONI’s presence on the Off-Corridor Access Lands or of its activities on or in connection with the Off-Corridor Access Lands arising out of the permission granted herein except to the extent any of such Costs arise out of or are contributed to by the negligence or willful misconduct by the Grantor.

7. Notices to be given to either party shall be in writing, personally delivered or sent by registered mail (except during a postal disruption or threatened postal disruption), telegram, electronic facsimile to the applicable address set forth below (or to such other address as such party may from time to time designate in such manner):

TO HONI:

Hydro One Networks Inc.
Real Estate Services
1800 Main Street East
Milton, Ontario L9T 7S3

Attention:	Real Estate Acquisitions
Tel:	905-875-2508
Fax:	905-878-8356

TO GRANTOR:

XXX

Email: XXX
Phone: XXX

8. Notices personally delivered shall be deemed to have been validly and effectively given on the day of such delivery. Any notice sent by registered mail shall be deemed to have been validly and effectively given on the fifth (5^{th}) business day following the date on which it was sent. Any notice sent by telegram, electronic facsimile or shall be deemed to have been validly and effectively given on the Business Day next following the day on which it was sent. “Business Day” shall mean any day which is not a Saturday or Sunday or a statutory holiday in the Province of Ontario. This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable herein. The parties hereto submit themselves to the exclusive jurisdiction of the Courts of the Province of Ontario.

9. Any amendments, modifications or supplements to this Agreement or any part thereof shall not be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of this Agreement.

Page 2 of 4

IN WITNESS WHEREOF the parties hereto have caused this Agreement to be executed by their duly authorized representatives as of the day and year first above written.

WITNESS:	**OWNER:**
______________________	______________________ l/s
Name:	Name: ***XXX***
Address:	
______________________	______________________ l/s
Name:	Name:
Address:	
______________________	______________________ l/s
Name:	Name:
Address:	
______________________	______________________ l/s
Name:	Name:
Address:	

HYDRO ONE
HST # 870 865 821 RT001

HYDRO ONE NETWORKS INC.

By: ______________________

Name:
Title:

I have authority to bind the Corporation

<u>SCHEDULE "A"</u>

PROPERTY SKETCH

Damage Claim

THIS MEMORANDUM OF AGREEMENT dated the ____ day of ____________, 2024

Between:

[INSERT NAME OF OWNER]

herein called the "**Claimant**"

- and-

HYDRO ONE NETWORKS INC.

herein called the "**Hydro One**"

Witnesseth:

The Claimant agrees to accept: **XXXXXXX ($XXX.XX)** in full payment and satisfaction of all claims or demands for damages of whatsoever kind, nature or extent which may have been done to date by Hydro One during the construction, completion, operation or maintenance of the works of Hydro One constructed on [INSERT LEGAL DESCRIPTION] which property the Claimant is the legal owner and which damages may be approximately summarized and itemized as:

[INSERT DESCRIPTION OF DAMAGE]

TOTAL $

Subject to Approval by Hydro One Networks Inc.

SIGNED, SEALED AND DELIVERED
In the presence of)
)
)
____________________________________) ____________________________(seal)
Print Name of Witness Name: XX

)
)
)
____________________________________) ____________________________(seal)
Print Name of Witness Name: XX

SYSTEM IMPACT ASSESSMENT

Please refer to **Attachment 1 of this Schedule** for the Final SIA, dated March 6, 2025, prepared by the IESO (SIA reference # CAA 2024-EX1285).

The Final SIA concludes 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 report are implemented.

Hydro One confirms that it will implement the requirements noted by the IESO in the SIA.

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Expedited System Impact Assessment Report

Final Report - Public

CAA ID: 2024-EX1285
Project: M31W Reinforcement (Buchanan TS x St. Thomas Line Tap)
Connection Applicant: Hydro One Networks Inc.

March 6, 2025

ieso
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Powering Tomorrow.

Acknowledgement

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

Disclaimer

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

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

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

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

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

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

Project Description

Hydro One Networks Inc. (the "connection applicant" and the "transmitter") is planning to uprate a 3.67 km section on the 230 kV circuit M31W extending from Buchanan Transformer Station (TS) (the "project").

The planned in-service date of the project is in January 2027.

Notification of Conditional Approval

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

IESO Requirements for Connection

General Requirements:

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

Appendix A: General Requirements

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

1. The connection applicant must notify the IESO at connection.assessments@ieso.ca as soon as they become aware of any changes to the project scope or data used in this assessment. The IESO will determine whether these changes require a re-assessment.
2. The connection applicant shall ensure that the BPS elements are in compliance with the applicable NPCC criteria and the BES elements in compliance with the applicable NERC reliability standards. To determine the standard requirements that are applicable, the IESO provides mapping tools titled "NPCC Criteria Mapping Spreadsheet" for BPS elements and "NERC Reliability Standard Mapping Tool/Spreadsheet" for BES elements at the IESO's website of Applicability Criteria for Compliance with Reliability Requirements.

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

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

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

   However, like any other system element in Ontario, the BPS and BES classifications of the project will be periodically re-evaluated as the electrical system evolves.
3. The connection applicant shall ensure that the project's equipment meet the voltage requirements specified in section 4.2 and section 4.3 of the Ontario Resource and Transmission Assessment Criteria (ORTAC).
4. According to Section 6.1.2 of the TSC, the connection applicant must ensure the project's transmission connection equipment is designed to withstand the fault levels in the area. According to Section 6.4.4 of the TSC, if any future system changes result in an increased fault level higher than the project's equipment capability, the connection applicant is required to replace that equipment with higher rated equipment capable of withstanding the increased fault level, up to the maximum fault level specified in Appendix 2 of the TSC.

   The connection applicant shall ensure that the circuit breakers/switchers installed at the project have rated interrupting time that satisfies Appendix 2 of the TSC. Fault interrupting devices installed at the project must be able to interrupt fault currents at the applicable maximum continuous voltage as specified in Section 4.2 and Section 4.3 of ORTAC.
5. The connection applicant shall ensure that the protection systems are designed to satisfy all the requirements of the TSC. New protection systems must be coordinated with existing protection systems. Protection systems within the project shall only trip the appropriate equipment isolating the fault.

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

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

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

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

6. The connection applicant shall ensure that the connection equipment is designed to be fully operational in all reasonably foreseeable ambient conditions. Failures of the connection equipment must be contained within the project and have no adverse impact on the IESO-controlled grid.
7. In accordance with Section 7.4 of Chapter 4 of the Market Rules, the connection applicant shall provide to the IESO the applicable telemetry data listed in Appendix 4.16 of the Market Rules on a continual basis. The data shall be provided in accordance with the performance standards set forth in Appendix 4.20 and Appendix 4.21, subject to Section 7.6A of Chapter 4 of the Market Rules. The whole telemetry list will be finalized during the IESO's Market Registration process.

   The connection applicant must install monitoring equipment that meets the requirements set forth in Appendix 2.2 of Chapter 2 of the Market rules. As part of the IESO's Market Registration process, the connection applicant must also complete end to end testing of all necessary telemetry points with the IESO to ensure that standards are met and that sign conventions are understood. All found anomalies must be corrected before IESO's final approval to connect any phase of the project is granted.
8. The connection applicant must initiate the IESO's Market Registration process at least four months prior to the commencement of any project related outages. Once the IESO's Market Registration process has been successfully completed, the IESO will provide the connection applicant with a Registration Approval Notification (RAN) document, confirming that the project is fully authorized to connect to the IESO-controlled grid. For more details about this process, the connection applicant is encouraged to contact IESO's Market Registration at market.registration@ieso.ca

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

Appendix B: Data Verification (Confidential)

Appendix C: Technical Assessments (Confidential)

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

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CUSTOMER IMPACT ASSESSMENT

Please refer to **Attachment 1** of this Schedule for the Final CIA prepared by Hydro One.

The Final CIA concludes that the Project is expected to have no material adverse impact on the reliability of the transmission connected customers in the area.

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Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

CUSTOMER IMPACT ASSESSMENT

M31W REINFORCEMENT
(BUCHANAN TS X ST. THOMAS LINE TAP)

FINAL

CIA ID: 2025-038
Revision: Revision 1
Date: December 15, 2025

Issued by:
Transmission System Planning Division
Hydro One Networks Inc.

Prepared by:

Thomas Tang, P.Eng.
Network Management Engineer
Transmission System Planning

Approved by:

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

Disclaimer

This Customer Impact Assessment ("CIA") is being performed in accordance with Hydro One Networks Inc.'s ("Hydro One") Customer Impact Assessment Procedure (Section 2.4) in Hydro One's Ontario Energy Board ("OEB") approved Transmission Connection Procedures ("TCP") and Section 6.41 of the OEB's Transmission System Code ("Code"). Hydro One performs a CIA where Hydro One has determined prior to conducting the CIA that one or more existing Hydro One transmission customers may be impacted by a proposed new or modified connection ("Proposed Project"). The CIA is intended to highlight impacts of the Proposed Project, if any, on existing Hydro One transmission customers early in the project development process and also provide an opportunity for existing Hydro One transmission customers that may be impacted by the Proposed Project to bring forward any concerns that they may have.

Please note that:

- the fault levels computed by Hydro One as part of this CIA are meant to assess current conditions and are not to be used by any person to size equipment or make other design decisions; and
- the estimate of the outage requirements identified in this CIA are subject to change to accommodate the requirements of the IESO and other regulatory or municipal authority requirements.

Hydro One may revise the result(s) of this CIA and issue CIA revision(s):

i. where there are subsequent changes to the Proposed Project, the required transmission system modifications or the implementation plan that changes the impact of the Proposed Project on one or more existing connected transmission customers; and
ii. to accommodate the IESO's requirements in respect of the Proposed Project identified in either the System Impact Assessment ("SIA") or any revision(s) of the SIA for the Proposed Project.

Hydro One shall not be liable to anyone (including, without limitation, any existing transmission customer that Hydro One determined may be impacted by the Proposed Project) under any circumstances whatsoever for any: (i) direct damages resulting from or in any way related to the reliance on, acceptance or use of the CIA (and where applicable, any CIA revision(s)), in whole or in part, unless such liability arises under section 6.4 of the Code or the terms of a contract made between Hydro One and that person or entity with respect to the Proposed Project; and/or (ii) indirect or consequential damages, loss of profit or revenues, business interruption losses, loss of contract or loss of goodwill, special damages, punitive or exemplary damages, whether any of the said liability, loss or damages arises in contract, tort or otherwise.

1. Purpose

This Customer Impact Assessment ("CIA") study assesses the potential impact of the line conductor upgrades for a 3.67 km section on the 230 kV circuit M31W extending from Buchanan Transformer Station ("TS") to Old Victoria Road Junction ("JCT"), the St. Thomas Line Tap location, on the transmission customers in the area.

In accordance with Section 6 of the Ontario Energy Board's Transmission System Code ("TSC"), Hydro One Networks Inc. ("Hydro One") is to carry out a CIA study to assess the impact of proposed new or modified connections on existing customers. This assessment does not evaluate the overall impact of the project on the bulk electricity system. As part of the Connection Assessment and Approval ("CAA") process, the impact of the proposed facility on the bulk electricity system is the subject of the System Impact Assessment ("SIA"), which was carried out by the Independent Electricity System Operator ("IESO"). The IESO has documented such findings for the project in the SIA report CAA ID: 2024-EX1285, March 6, 2025.

In their report, the IESO concluded that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system.

1.1 Project Description

M31W is a 230 kV circuit from Buchanan TS to Middleport TS and, along with the M32W and M33W, services Ingersoll TS, Karn TS, and the new Centennial TS.

From the IESO Central-West Bulk Plan, issued April 18, 2024, the IESO has recommended rebuilding the M31W circuit between Buchanan TS and the M31W Tap Point to the new Centennial TS, now called Old Victoria Road JCT, with higher capacity conductors on double circuit towers, such that the another circuit could be accommodated in the future. At this time, only one circuit, M31W, will be strung on the towers contemplated within this project.

Hydro One's proposed M31W Reinforcement project covers reconductoring of about 3.67 km of 230 kV circuit line M31W between Buchanan TS to Old Victoria Road JCT.

The planned in-service date of the project is in Q1 2027.

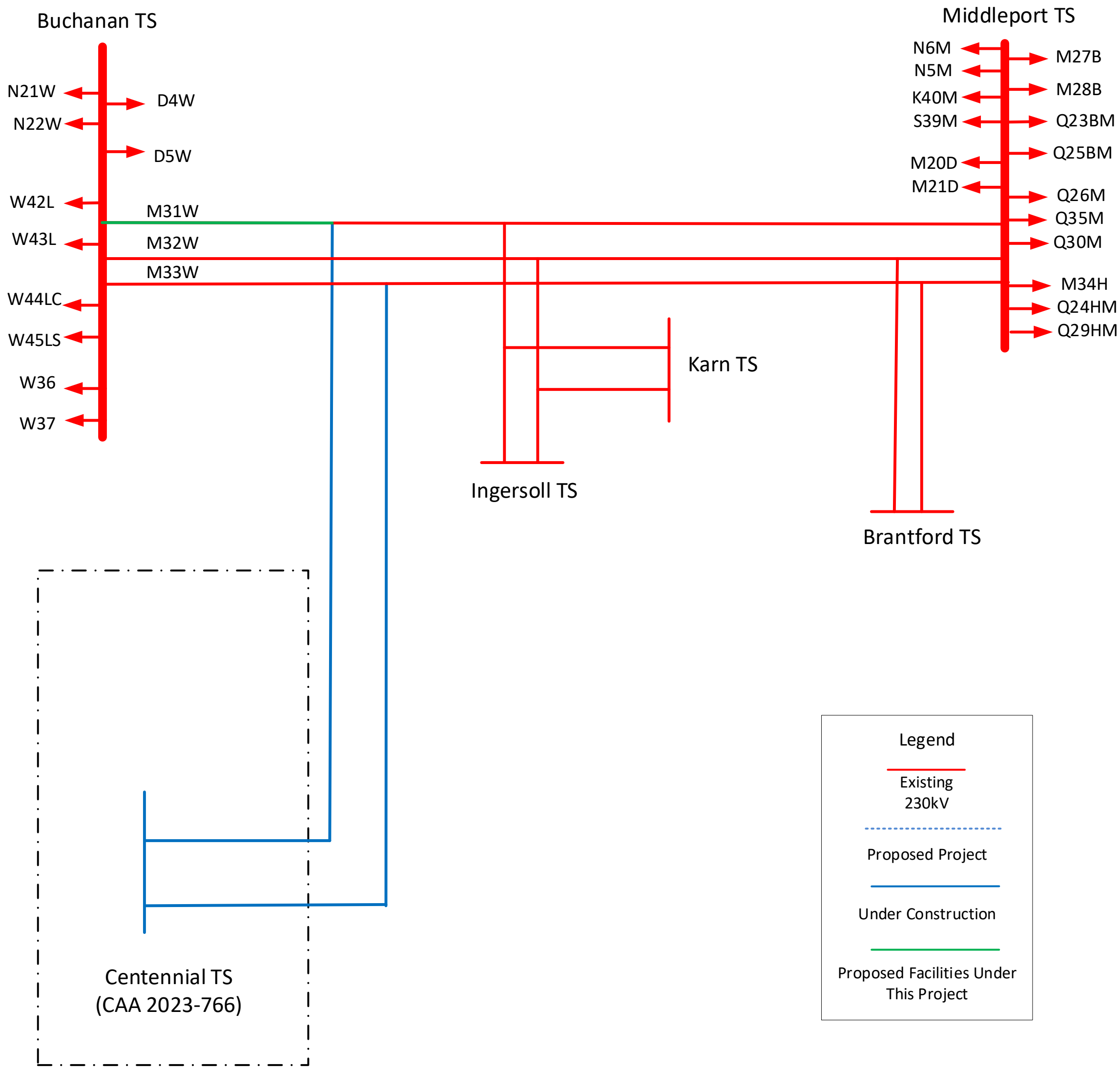

Figure 1 - Single Line Diagram for Project Area

1.2 Connected Customers in Study Area

The focus of this study is to assess the impact of the proposed project on existing customers connected to Hydro One's transmission system in the electrical vicinity ("Study Area") of the project, shown in Table *1* below.

Table 1 - List of Area Customers

Station Name	**Connection**	**Customer Name**
Brantford TS	M32W/M33W	GrandBridge Energy Inc.
Buchanan TS (DESN)	W42L/W43L	London Hydro Inc.
Centennial TS	M31W/M33W	Industrial Customer #1
Ingersoll TS	M31W/M32W	Hydro One Networks Inc. [Distribution]

2. Technical Studies

2.1. Short Circuit Study

Short circuit studies were carried out to determine fault levels at impacted customer connection points before and after the incorporation of the project. These results would help customers determine if the proposed project results in short-circuit levels that are within the ratings of their existing equipment.

The circuit impedance with the replacement conductors is not materially different from the existing impedance and, therefore, there are no significant changes to line flows and short circuit levels following the incorporation of the project.

The short circuit levels with and without the project are provided in Appendix A.

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

2.2. Thermal Assessment

There are no changes to the circuit configuration as a result of this reconductoring project.

The circuit impedance with the replacement conductors is not materially different from the existing impedance and, therefore, there are no significant changes to line flows following the incorporation of the project.

3. Supply Reliability to Customers

3.1 Connection Configuration

There are no changes to the circuit configuration as a result of this reconductoring project.

In the IESO SIA CAA ID 2024-EX1285, dated March 6, 2025, the IESO concluded that the proposed connection of the project is expected to have no material adverse impact on the reliability of the integrated power system.

4. Conclusion

This Customer Impact Assessment (CIA) study has reviewed the impact of the conductor upgrade project for the local customers connected to the 230kV M31W circuit.

The fault levels at all stations in the area experience no significant change as a result of the project. Customers are requested to review fault levels provided in Appendix A to ensure that the capability of their equipment is not exceeded.

The study has confirmed that the proposed project can be incorporated without adverse impact on Hydro One Transmission customers.

Appendix A <u>Short Circuit Results</u>

		BEFORE PROJECT				AFTER PROJECT				% DIFFERENCE	
		3-PHASE		SLG		3-PHASE		SLG		3-PHASE	SLG
Bus	Bus kV	SYMM	ASYMM	SYMM	ASYMM	SYMM	ASYMM	SYMM	ASYMM	SYMM	SYMM
Brantford TS Z Bus	27.6	15.245	17.197	11.56	14.484	15.245	17.197	11.56	14.484	0.00%	0.00%
Brantford TS Y Bus	27.6	14.39	16.224	10.777	13.61	14.39	16.224	10.777	13.61	0.00%	0.00%
Buchanan TS B Bus	27.6	15.088	17.78	11.32	14.534	15.088	17.78	11.32	14.534	0.00%	0.00%
Buchanan TS Y Bus	27.6	15.468	18.092	11.858	15.064	15.468	18.092	11.858	15.064	0.00%	0.00%
Centennial TS	27.6	16.697	21.443	12.203	16.859	16.697	21.443	12.203	16.859	0.00%	0.00%
Ingersoll TS Z Bus	27.6	13.945	15.396	10.907	13.473	13.945	15.397	10.907	13.474	0.00%	0.00%
Ingersoll TS E Bus	27.6	13.74	15.238	10.924	13.52	13.739	15.238	10.923	13.521	-0.01%	-0.01%
Karn TS K7 K12 Bus	115	15.763	17.953	18.432	21.91	15.762	17.954	18.43	21.911	-0.01%	-0.01%

REGIONAL AND BULK PLANNING

The reinforcement of the 230 kV transmission line (M31W) between Buchanan TS and Old Victoria Road Junction is a newly emergent bulk system need and not mentioned in any previous regional planning IRRP and RIP reports. The next cycle of the regional planning process is underway with the scope assessment phase completed in April 2025. As noted in the scoping assessment outcome report[1], this Project is driven by bulk planning needs. The most recent IESO bulk planning report, entitled “Central-West Bulk Plan” dated April 18, 2024, in support of this Project is provided in **Attachment 1 of this Schedule**. This report concludes that the construction of the Project is the most feasible and cost-effective option that alleviates the transfer capability need in the area, increases supply capability and maintains system reliability, consistent with the IESO’s evidence in support of need provided in **Exhibit B, Tab 3, Schedule 1, Attachment 1**.

---

[1] IESO London Area Scoping Assessment Outcome Report, dated April 25, 2025. https://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/London-Area/London-Area-20250425-Scoping-Assessment-Outcome-Report.pdf

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Central-West Bulk Plan

April 18, 2024

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Powering Tomorrow.

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List of Abbreviations

AAR	Annual Acquistion Report
AIS	All In-Service
APO	Annual Planning Outlook
ATB	Annual Technology Baseline
BBN	Burlington Beach Niagara
BES	Buchanan East Supply
BESS	Battery Energy Storage System
BLIP/NBLIP	Buchanan-Longwood Input/Negative Buchanan-Longwood Input
BWS	Buchanan West Supply
CAD	Canadian dollars
CGS	Customer Generating Station
CKLS	Chatham-Kent/Lambton/Sarnia
DESN	Dual Element Spot Network
EV	Electric Vechicle
FABCW	Flow Away from Bruce Complex plus Wind
FALS	Flow Away from Lambton-Sarnia
FETT	Flow East to Toronto
FETL	Flow East Towards London
FIL	Flow Into Lakeshore
GH	Greenhouse
GTA	Greater Toronto Area
ICAP	Installed Capacity
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
KWCG	Kitchener/Waterloo/Cambridge/Guelph
LTE	Long Term Emergency
MECP	Ministry of Environment, Conservation and Parks
MVA	Megavoltage Ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
POG	Powering Ontario's Growth
QFW	Queenston Flow West
RAS	Remedial Action Scheme
RFP	Request For Proposals
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment

SS	Switching Station
STE	Short Term Emergency
TS	Transformer Station
USD	United States dollars
UVLS	Under Voltage Load Shedding
VW	Volkswagen
WOC	West of Chatham
WOL	West of London input

1 Executive Summary

This document describes the results of the Central-West Bulk Plan (the "Plan") that the Independent Electricity System Operator (IESO) has undertaken to assess the reliability of the bulk transmission system in the Central-West area. The Central-West area encompasses a large portion of southwestern Ontario, including the West, Southwest, Niagara and Bruce electricity Zones,[1] and contains all the high voltage levels that operate in Ontario: 500 kV, 230 kV and 115 kV. This area stretches roughly from the Municipality of Waterloo and City of Hamilton in the east, to the City of Sarnia and City of Windsor in the west.

This system interconnects large generators in the Sarnia-Lambton, Windsor, Bruce and Niagara areas, with existing load centres. It provides interconnection points with Michigan via Windsor and Sarnia-Lambton and borders the Niagara region, which provides interconnection points with New York. The area is also connected via the 230 kV and 500 kV system at Middleport Transformer Station (TS), within the County of Brant, to central and eastern Ontario, providing a strong path between the Central-West area and the rest of the province.

There is strong electric vehicle and battery-related manufacturing growth in Ontario that is expected to continue. The automotive sector in Ontario is growing, with significant new developments from Stellantis in Windsor to Volkswagen in St. Thomas. In addition, southwestern Ontario's population is expected to grow by two million people by the end of this decade. As a result, Ontario's electricity demand is rising, especially in the Central-West area.

The IESO's bulk planning looks at the flow of power between broad areas of the province and growth factors informed by customers and policy decisions. Thus, the focus of this Plan is confirmed economic development projects (defined as "Firm Load"), such as the Volkswagen Electric Vehicle ("EV") plant in St Thomas and spin-off loads totalling 620 MW. The other focus of this plan is 500-650 MW of potential economic development in each of the five planning regions of interest, defined as "Potential Load," which include: London Area, Kitchener/Waterloo/-Cambridge/Guelph, Windsor-Essex, Chatham-Kent/Lambton/Sarnia, and Burlington to Nanticoke regions.

The purpose of the Central-West bulk study is to:

- Ensure continued, reliable bulk supply to the London Area region, in light of the Firm Load and potential economic development in the region, including consideration of the load connection configuration as it impacts the bulk system – the focus of this Plan
- Proactively investigate a range of potential growth scenarios, across the five regions of interest[2] within southwestern Ontario, to inform future plans and possible system reinforcements if/when large new loads materialize – considered in this Plan, with further bulk or regional analysis identified, as required

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[1] Visit the IESO's zonal map illustrating the 10 electrical zones.

[2] There are seven regions in southwestern Ontario, five of which were identified as regions of interest for the Central-West Bulk Plan.

Based on the growth scenarios, and accounting for the transmission recommendations from the 2019 Windsor-Essex and 2021 West of London bulk studies that are planned to come into service between now and 2030, the following reliability issues were identified:

- Unacceptable impact to the transfer capability of the bulk transmission interface (Negative Buchanan Longwood Input [NBLIP]) as 600 MW of major economic development is added in the London Area region, on top of forecast annual growth
- Dynamic voltage support needed as 900 MW of major economic development is added in the London Area region

Considering the most cost-effective option that mitigates forecast demand growth risk, and preserves options to increase system capability in the future, the following integrated solutions are recommended to address the reliability needs for the Firm Load and accommodate Potential Load growth across the Central-West area over the long-term:

- Reconstruct the M31W circuit between Buchanan TS and the Firm Load tap point, approximately 2-5 km in length, with higher capacity double circuit towers, strung with one circuit but capable of accommodating a second circuit in the future, if/when needed. This will address the unacceptable impact to the transfer capability of the NBLIP interface as 600 MW of load is added to the London Area region.
- If more than 300 MW of Potential Load materializes in the London Area region, implement dynamic voltage devices at Ingersoll TS, as well as across the Central-West area as demand grows. Since this is a long-term need, firm recommendations are not being made at this time so as to be responsive to when and where load materializes. This will address the need as 900 MW of incremental load is added in the London Area region.

Reconstruction of the M31W circuit represents the lowest-cost option, estimated to result in a net present cost savings of approximately $4 billion -$17 billion, compared to the least-cost, non-emitting resource alternative – new wind in combination with a new battery energy storage system.

The reconstruction will relieve the unacceptable impact to the transfer capability of the NBLIP interface and allow the connection of approximately 300 MW of Potential Load in the London Area region beyond the Firm Load (i.e., 900 MW in total). It is recommended that this work be initiated immediately, assuming a five-year lead time for implementation.[3] Moreover, rebuilding the M31W circuit with double circuit towers, would preserve the option to quickly increase the transfer capability across the London Area region even further, while maintaining load security, if the Potential Load location or amount shifts from the assumptions in this Plan.

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth (POG) report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. As per that report, the Ontario government is planning for a more electrified Ontario, where economic growth continues to drive new jobs and emissions continue to be reduced. The IESO's South and Central Ontario bulk planning study being initiated in 2024 will consider the objectives of the POG report across southwestern Ontario, as detailed in the IESO's 2024 Annual Planning Outlook.

[3] Once the dynamic voltage device is installed, further load can be supplied until the next thermal limitation is reached.

Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact. Regional concerns identified in the Central-West Plan for the Windsor-Essex and Kitchener-Waterloo/Cambridge/Guelph regions will inform ongoing or upcoming regional planning activities.

2 Introduction

2.1 Power System Planning in Ontario

The Independent Electricity System Operator (IESO) is responsible for conducting independent planning for electricity generation, demand management, conservation and transmission in the Province of Ontario.[4] In carrying out this mandate, the IESO undertakes planning activities to ensure that the province has, and will continue to have, an adequate and reliable supply of resources and transmission to meet Ontario's electricity needs. The IESO's planning generally consists of regional planning and bulk system planning. These are two separate but inter-related planning activities. Regional planning is carried out according to a regional planning process endorsed by the Ontario Energy Board (OEB). Regional planning produces plans that address system issues that are local in nature, within 21 planning regions covering the province. Bulk system planning is carried out by the IESO to address system issues that are more provincial in nature, such as the province-wide need for generation capacity, and transmission system solutions to enable transporting power reliably and economically across the province. The IESO also conducts regulatory compliance studies and completes reporting requirements, such as those set out in the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) criteria.

In February 2021, the bulk power system planning process was formalized through the High-Level Design Overview, to make the design and implementation of plans more consistent, timely, and transparent. As part of that process, the IESO utilizes the Annual Planning Outlook (APO) as the reporting vehicle that summarizes the forecasted bulk system reliability issues over the next 20 years. Since 2022, the APO describes how the IESO plans to address each bulk issue, either through an individual bulk system study or resource procurements. System issues reported in the APO that require a bulk system study are referenced in the APO Schedule of Planning Activities, which communicates the timelines for initiating bulk system studies.

2.2 Central-West Bulk Plan

As identified in the 2022 APO's Schedule of Planning Activities, this study was originally scheduled to begin in 2024. However, due to the recent Volkswagen electric vehicle (EV) plant announcement in St. Thomas and rapidly evolving economic development opportunities across southwestern Ontario, this work was advanced to start in mid-2023.

[4] The IESO's objects, including for power system planning, are as set out in the Electricity Act, 1998.

The objectives of this Plan are to:

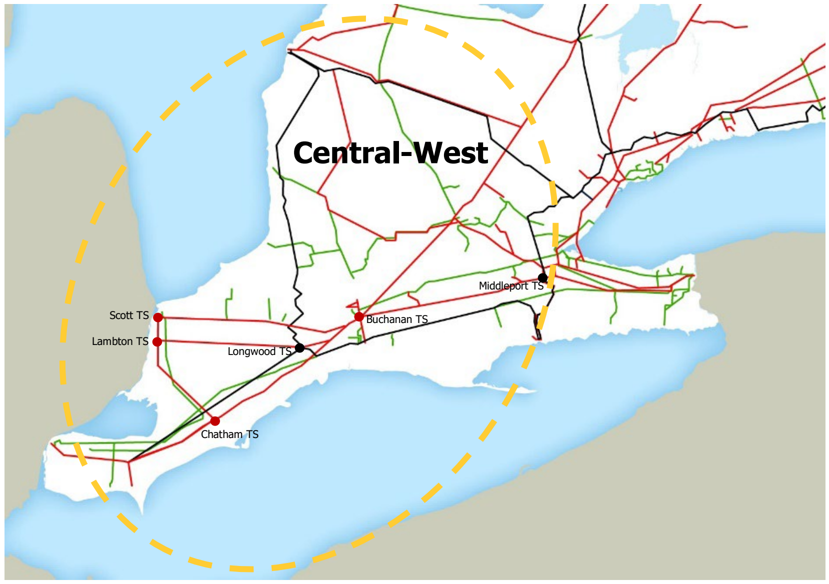
- Ensure continued, reliable bulk supply to the London Area region, in light of the Firm Load and potential economic development in the region, including consideration of the load connection configuration as it impacts the bulk system[5] – the focus of this Plan
- Proactively investigate a range of potential growth scenarios, across the five regions of interest within southwestern Ontario, to inform future plans and possible system reinforcements if/when large new loads materialize – considered in this Plan, with further bulk or regional analysis identified, as required

Study scope and objectives are in response to customers, policy decisions, economic development, and governmental direction. This Plan summarizes the results of the bulk assessment, focused on the first objective, as well as any bulk impacts of large new loads in other areas within the Central-West area. Remaining studies, currently planned to be incorporated into a new South and Central Ontario bulk study, will complete the second objective, while being responsive to policy decisions and economic development as the sector evolves.

The Central-West area encompasses a large portion of southwestern Ontario, including the West and Southwest electricity Zones, which is a system that contains all high voltage levels that operate in Ontario: 500 kV, 230 kV and 115 kV. This area stretches roughly from the Municipality of Waterloo and City of Hamilton in the east, to the City of Sarnia and City of Windsor in the west, as illustrated in **Figure 1**.

[5] The connection facilities, including design and location of the customer supply station, are out of scope of bulk planning. This is determined by the customer and connecting transmitter, Hydro One in this case, and taken as inputs into this Plan. However, as detailed in Appendix C, this Plan did consider which bulk circuits that customer connection should tap onto, since there were broader bulk implications for growth in general.

Figure 1 | Geographic Map Illustrating Central-West Area



This system interconnects large generators in the Sarnia-Lambton, Windsor, Bruce and Niagara areas with existing load centres, and encompasses the growing industrial sector in and around London and across southwestern Ontario. It provides four interconnection points with Michigan's power system via Windsor and Sarnia-Lambton, and borders the Niagara region, which provides interconnection points with New York.

The bulk of the electrical supply to the London Area region is transmitted into southwestern Ontario through 230 kV circuits from Buchanan Transformer Station (TS) to Scott TS, Lambton TS, and Chatham Switching Station (SS), carrying Sarnia-Lambton generation; 500 kV circuits from the Bruce complex; and the 500 kV and 230 kV network emanating from Middleport TS to provide supply from other provincial resources. Over the last decade, prevailing power flows on the bulk system have been east towards Toronto, from gas generation located largely in Sarnia-Lambton, as well as nuclear generation in Bruce. However, with load changes across southwestern Ontario, bi-directional flow is expected in the future as new load connects.

This Plan is organized into the following sections:

- Section 2, "Introduction," provides an overview of power system planning and the purpose of the Central-West Bulk Plan
- Section 3, "Background and Scope," provides background on the areas of interest within the Central-West area, specifically the London Area, Windsor-Essex, Chatham-Kent/Lambton/Sarnia, Kitchener/Waterloo/Cambridge/Guelph, and Burlington to Nanticoke regions
- Section 4, "Demand Forecasts," details the demand forecast assumptions
- Section 5, "Existing Supply to the Broader Central-West Area and London Area Region," presents the existing supply sources and resource scenarios considered in the bulk study
- Section 6, "Needs Determination," provides the results of the bulk studies, transfer capabilities and congestion considerations
- Section 7, "Options Evaluation and Recommendations," analyzes the transmission and resource alternatives considered to meet the supply capacity needs
- Section 8, "Community and Stakeholder Engagement," goes over the engagement activities to date and moving forward for the Central-West area

- Section 9, "Conclusions and Recommendations," summarizes the recommendations for the Central-West area and implications on subsequent bulk and regional studies
- Appendix A: Application of Criteria outlines the planning standards applied, and contingencies considered
- Appendix B: Economic Assessment Assumptions details the options and assumptions associated with the cost comparison for the alternatives
- Appendix C: Connection Configuration Requirement presents the Firm Load connection configuration requirement

3 Background and Scope

3.1 Background

This Plan reviews the Central-West bulk transmission system to identify bulk system needs from a planning perspective, encompassing the area roughly from the Municipality of Waterloo and City of Hamilton in the east, to the City of Sarnia and City of Windsor in the west. The scope of this study is limited to the bulk system, so while the footprint of the Central-West area encompasses more than what is listed below, only elements that would result in bulk limitations are included. Generally, this includes the 500 kV and 230 kV systems, and excludes the 115 kV system and radial lines. Load connection details and associated local concerns are also out of scope. The connection facilities for confirmed loads, including design and location of the customer supply station, are determined by the customer and connecting transmitter and taken as inputs into this study. However, bulk implications of the load connection were considered (i.e., optimal configuration of the load connection line to the bulk system). In addition, certain additional elements are excluded from the scope of this Plan in cases where a previous study was recently completed and reinforcements have been recommended (e.g., the Lambton to Chatham circuits). For example, anything west of Chatham SS, would be considered a regional need, to be addressed through ongoing regional planning.

The following infrastructure was monitored as part of the scope of this Plan:

- **Transmission Stations:** Buchanan TS, Detweiler TS, Middleport TS, Ingersoll TS, Karn TS, Preston TS, Burlington TS, Beach TS, Longwood TS, Nanticoke TS, Lakeshore TS, and Edgeware TS
- **Transmission Circuits:**
    - **230 kV:** M31W, M32W, M33W, D4W, D5W, M20D, M21D, M27B, M28B, Q23BM, Q25BM, M34H, Q24HM, Q29HM, B18H, B20H, W44LC, W45LS, W42L, W43L, N1M, N5M, N6M, K40M, N20K, S39M, N37S, B20H, B18H, M34H, N21W, N22W, L24L, L26L, D6V, D7V, T36B, T37B, T38B, T39B.
    - **500 kV:** N582L, N581M, N582M, new Longwood to Lakeshore single circuit (LxH), M585M, V586M.

The Central-West area encompasses several electrical planning regions, five of which have been identified as regions of interest, as described in more detail below.

3.2 Regions of Interest

In response to customers, policy decisions, economic development, and governmental direction, five planning regions[6] were identified as requiring proactive investigation to understand the impact of economic development on the bulk system capability, as well as to inform future plans and potential system reinforcements if/when large new loads materialize. These planning regions include the London Area, Kitchener/Waterloo/Cambridge/Guelph (KWCG), Windsor-Essex, Chatham-Kent/Lambton/Sarnia (CKLS), and Burlington to Nanticoke regions, as illustrated in **Figure 2**. Note that, the electricity planning regions are defined by electricity infrastructure boundaries, not municipal boundaries.

Each of the regions and their electricity growth drivers are described in the following subsections.

Figure 2 | Geographic Map of Five Regions of Interest for the Central-West Study

The other two regions in southwest Ontario – Niagara and Greater Bruce/Huron – were not included in the scope of this study, either because recent plans were completed that considered additional load beyond the regional reference forecast, or they are a net source of electricity. For the Niagara region, an Integrated Regional Resource Plan (IRRP) was recently completed in 2022, which set out a plan that enables approximately 140 MW of additional supply to Port Colborne/Welland by 2028, based on recommended reinforcements (converting Crowland TS to a new 230 kV station, supplied by new 230 kV double circuit lines from Q24HM and Q29HM).[7] Additional load beyond 140 MW could also potentially be supplied from the new 230 kV circuits pending further studies, if required. Conversely, the Greater Bruce/Huron region was not included, as no supply transfer needs were identified in the recently completed regional plan, and the region is a large net source of electricity for the province with over 7,000 MW of generation.[8]

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[6] Planning regions are the IESO-defined 21 electricity planning regions. Refer to the Regional Planning website for more details: https://www.ieso.ca/en/Get-Involved/Regional-Planning/About-Regional-Planning/Overview

[7] Refer to the 2022 Niagara IRRP, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-IRRP-Report.ashx

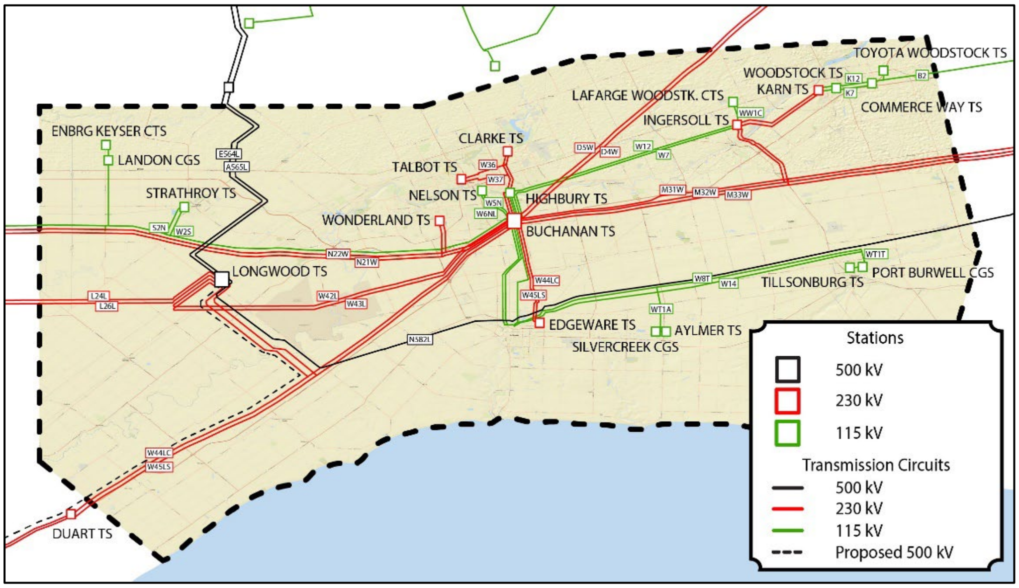
[8] Refer to the 2021 Southern Huron-Perth IRRP, https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Bruce-Huron/Southern-Huron-Perth-IRRP-20210916.ashx

3.2.1 London Area

The London Area region is located in southwestern Ontario and includes the municipalities of Oxford County, Middlesex County, Elgin County, City of London, City of Woodstock, and City of St. Thomas. Regional planning for the London Area region has historically been divided into five sub-regions: Greater London, Alymer-Tillsonburg, Strathroy, Woodstock, and St. Thomas.

The electricity infrastructure supplying the London Area region is shown in **Figure 3**. The region is supplied from 115 kV and 230 kV transmission lines and stations that connect at the Buchanan and Longwood transformer stations. The 500/230 kV auto-transformers at Longwood TS and the 230/115 kV auto-transformers at Buchanan TS and Karn TS provide the major source of supply to the area.

Figure 3 | Overview of London Area Region



This region has three transmission-connected generating stations, including a 40 MW windfarm connected to the 115 kV circuit west of Strathroy TS, a 99 MW windfarm connected to the 115 kV circuit near Tillsonburg TS, and a 10 MW solar generator connected to the 115 kV circuit near Aylmer TS.

The London region is one of the fastest growing urban centres in Canada, with its population increasing by 10 per cent between 2016 and 2021, with newcomers from other countries, as well as other Canadian cities.[9] With large industrial facilities both existing and planned in the area, including those for Volkswagen, Amazon and Maple Leaf Foods, employment opportunities and housing starts are projected to continue to grow.

[9] https://www12.statcan.gc.ca/census-recensement/2021/as-sa/98-200-x/2021001/98-200-x2021001-eng.cfm

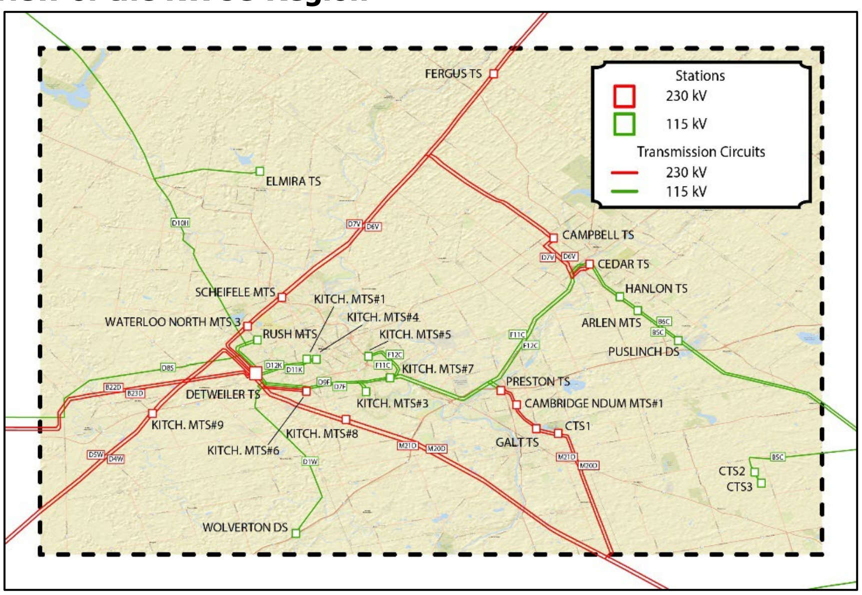
The second cycle of the London Area regional planning process proceeded directly to a Regional Infrastructure Plan (RIP), which was prepared by Hydro One in August 2022. At the time, the full regional process, or IRRP, was determined not to be required because no regional needs were identified. Instead, the load restoration need was assessed as part of Local Planning by Hydro One and the relevant Local Distribution Company.

3.2.2 Kitchener/Waterloo/Cambridge/Guelph

The KWCG region is located in southwestern Ontario and encompasses the Region of Waterloo, the cities of Kitchener, Waterloo, Cambridge and Guelph, and the townships of Wellesley, Woolwich, Wilmot, North Dumfries, and portions of Perth and Oxford. Wellington County and the municipalities of Blandford-Blenheim, Centre Wellington, Guelph/Eramosa, and Puslinch are also included in the region. The KWCG region is summer-peaking and is served via 230 kV and 115 kV circuits originating from Detweiler TS and Burlington TS, and by load stations that tap double circuit 230 kV lines connecting to Detweiler from Orangeville (D6V and D7V), from Middleport (M20D and M21D) and from Buchanan (D4W and D5W). There are no transmission-connected resources in this area.

An overview of the KWCG region and the location of the electrical infrastructure are shown in **Figure 4**.

Figure 4 | Overview of the KWCG Region



The KWCG region electricity demand is a mix of residential, commercial, and industrial loads, encompassing diverse economic activities ranging from educational institutions to automobile manufacturing. While the industrial and commercial sectors are the largest consumers of electricity, high energy-consuming end uses such as air conditioning also play a significant role in contributing to peak electricity demand. The historical summer peak demand has fluctuated between 1,200 MW to 1,350 MW in recent years.

There are multiple factors affecting electricity demand within the KWCG region. The first factor driving electricity demand is population growth. In response to the Ontario's A Place to Grow plan, the Region of Waterloo completed the first phase of its review of the Regional Official Plan in 2022, which includes forecast population and employment growth. The Region of Waterloo estimated that the population will increase from 232,200 in 2006 to 341,500 in 2029, and that employment will increase from 106,100 in 2006 to 139,700 in 2029. The growth in population and employment will drive electricity demand for the next 20 years.

The second factor affecting electricity demand is the change in the industrial sector. The Region of Waterloo is internationally known for its leading-edge technology and advanced manufacturing industries, innovative educational institutions, vibrant agricultural communities, and the historically significant Grand River. The City of Kitchener is experiencing a conversion from being a manufacturing-oriented economy to a more diversified and balanced economy. Kitchener-Wilmot Hydro lost its top three load customers in the past 10 years. Meanwhile, more customers with smaller demand emerged in the industrial and commercial sectors.

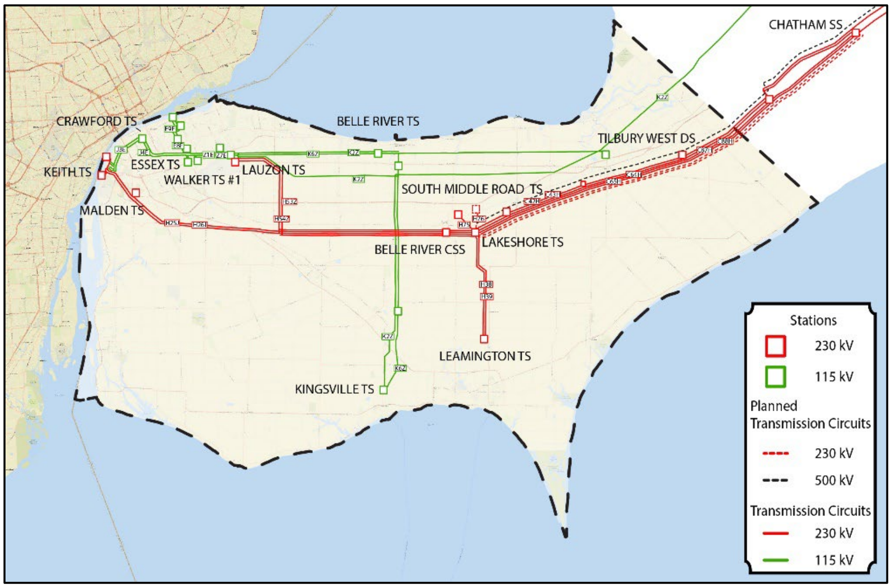
The third factor affecting electricity demand growth is the Region of Waterloo's Regional Official Plan. To support the provincial policy in the *Places to Grow Act*, as well as the city's efforts to intensify the Kitchener downtown area, the Region of Waterloo installed a light rail transit system between Waterloo and Kitchener, with a plan to extend the rail system to Cambridge. The installation of the light rail transit is spurring development along the train route in both the residential and commercial sectors.

The fourth factor affecting electricity demand is the rising awareness of renewable energy generation development, and conservation and demand management. As directed by the OEB, Kitchener-Wilmot Hydro is currently participating in multiple provincial renewable energy programs and conservation and demand management programs, which help control and reduce the electricity demand. Time-of-Use is also shifting demand and conserving energy as customers manage their electricity use and control their costs.

3.2.3 Windsor-Essex

The Windsor-Essex region is the southernmost portion of Ontario, extending southwest from the Municipality of Chatham-Kent to the City of Windsor. Electricity to Windsor-Essex is supplied from the rest of the province through two 230 kV double circuits and two 115 kV single circuits. The main 230 kV transmission corridor in the region connects with the rest of the province at Chatham SS in the Municipality of Chatham-Kent, as shown in **Figure 5**.

Figure 5 | Overview of Windsor-Essex Region



Electricity demand in the region is growing at a rapid pace, as agriculture and manufacturing continue to develop. The Kingsville-Leamington area within the Windsor-Essex region is home to North America's largest concentration of greenhouse vegetable production. Growth has been driven by strong indoor agricultural growth, mainly vegetable greenhouses. This also includes, in part, cannabis, specifically through existing greenhouses switching to lit indoor facilities, expansion of greenhouse facilities, and supplemental load to support the agricultural sector. In addition, Windsor remains the country's manufacturing and automotive powerhouse, with significant recent investments in electric vehicle battery manufacturing. While agriculture has been driving electricity demand growth and needs in the region over the last few years, especially in winter, economic development across the region, electrification, and local climate action plans are expected to be key factors for future electricity needs.

Electricity planning in Ontario typically occurs on a cyclical basis. However, due to the rapidly growing agricultural sector, planning in southwestern Ontario has been occurring on a continuum over the last five years, with no signs of slowing down. The 2019 Windsor-Essex bulk study occurred in parallel with the 2019 Windsor-Essex IRRP, focused on increasing the overall transfer capability of the bulk transmission system west of Chatham in order to reliably supply the forecast load growth in the Kingsville-Leamington area and Windsor-Essex region. In 2021, the West of London (WOL) bulk plan considered the area from outside the western edge of the City of London, to the City of Sarnia in the northwest, and to the City of Windsor in the west. The WOL bulk plan looked to address remaining bulk transmission system constraints east of Chatham, ensure adequate supply to the larger WOL area, and, given the expiry of generation contracts in the area, identify any transmission constraints limiting the ability of supply resources and imports within WOL to meet provincial needs. In tandem, the 2022 Windsor-Essex Addendum was undertaken to address remaining local needs in Kingsville and Leamington.

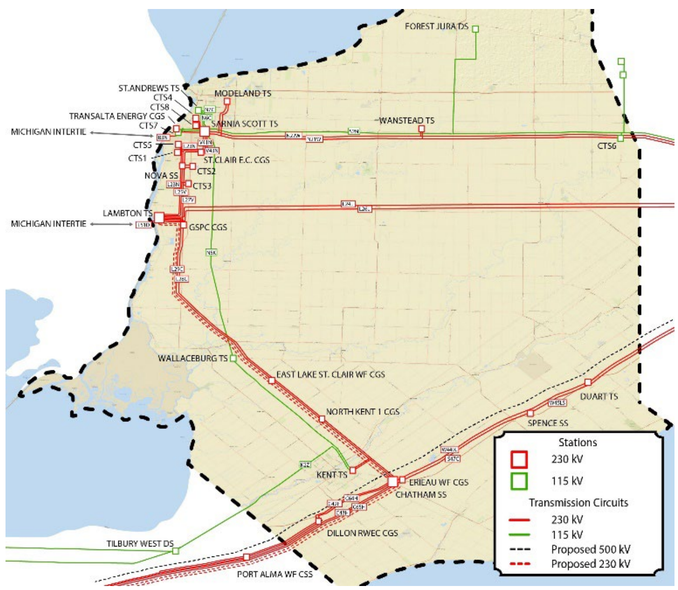
As a result, a significant number of recommendations have been made to date, ranging from transmission (such as new supply stations, transmission lines and a switching station) and local and zonal generation requirements, to non-wires recommendations (including a targeted call for indoor agriculture projects and efficiency incentives). The next cycle of regional planning is ongoing, with an IRRP that began in May 2023. The IRRP complements this Central-West Bulk Plan by focusing on regional concerns, including supply within the region, the evolving economic development opportunities in the Windsor area and agricultural load in the Kingsville-Leamington area, as well as assessing the need for a transmission reinforcement between Lakeshore TS and Windsor.

3.2.4 Chatham-Kent/Lambton/Sarnia

The Chatham-Kent/Lambton/Sarnia region is located west of the City of London and east of Essex County, and includes the municipalities of Lambton Shores and Chatham-Kent, the townships of Petrolia, Plympton-Wyoming, Brooke-Alvinston, Dawn-Euphemia, Enniskillen, St. Clair, Warwick, and Villages of Oil Springs and Point Edward. Portions of Huron County (Municipality of South Huron) and Elgin County (Municipality of West Elgin) are also included in the region. This region also has a number of First Nations and Métis Nation of Ontario community councils.

An overview of the Chatham-Kent/Lambton/Sarnia region and the location of the electrical infrastructure are shown in **Figure 6**.

Figure 6 | Overview of the Chatham-Kent/Lambton/Sarnia Region



This region is summer-peaking, however, forecast agricultural load growth in the Municipality of Chatham-Kent is winter-peaking. The region is currently supplied from a network of 115 kV and 230 kV transmission lines and stations, from the western edge of the City of London, to the City of Sarnia in the northwest, and the Municipality of Chatham-Kent in the southwest.

The bulk of supply in the region is transmitted from the 230 kV circuits between Lambton TS, Scott TS, and Chatham SS in the area, connected to the broader provincial system through Longwood TS and Buchanan TS in the east (N21W, N22W, L24L, L26L, W44LC and W45LS). It is also connected to the Windsor-Essex region in the west, through 230 kV circuits at Chatham. There is a significant amount of supply resources in Sarnia-Lambton, strategically located near the Dawn gas supply hub, as well as three of the four interconnections between Ontario and Michigan (B3N, L4D and L51D). This area also includes large petro-chemical industrial loads in Sarnia-Lambton, much of which are interdependent with the combined heat and power generators. There is approximately 2,300 MW of gas generation in the region, strategically located near the Dawn gas supply hub.

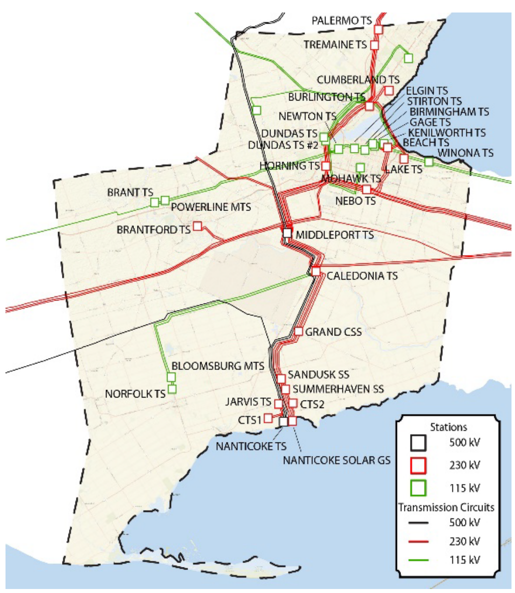
Growth in the Chatham-Kent/Lambton/Sarnia region has been driven by population growth, agricultural development in the Dresden area, and industrial growth in Sarnia-Lambton. The Municipality of Chatham-Kent was an early adopter and is a large supporter of renewable energy in Ontario. The County of Lambton and City of Sarnia house over 190,000 people, with electricity demand largely driven by the hub of traditional petro-chemical industrial loads and the emerging bio-industrial and clean energy economy. Since Sarnia-Lambton houses a large concentration of refineries and chemical producers that could switch from using high- to low-carbon hydrogen, the municipality is also positioning itself to play a key role in Ontario's hydrogen strategy.

3.2.5 Burlington to Nanticoke

The Burlington to Nanticoke region is located in southwestern Ontario and includes all or part of the following Counties and Districts: City of Hamilton, Brant County, the City of Brantford, Haldimand County, Norfolk County, and the Regional Municipality of Halton. The region includes several Indigenous communities that are located in or near the region.

An overview of the Burlington to Nanticoke region and the location of the electrical infrastructure are shown in **Figure 7**.

Figure 7 | Overview of the Burlington to Nanticoke Region



The Burlington to Nanticoke region is expected to have both organic growth and economic development projects across the region, along with strong industrial growth and interest in ensuring electricity infrastructure can accommodate economic development. In addition, significant community energy initiatives are planned across the region. As a result, the next cycle of regional planning is ongoing, focused on regional needs in the Hamilton, Brant and Caledonia-Norfolk sub-regions. On average, an annual growth of three per cent, four per cent, and 5 per cent is expected for the Hamilton, Brant and Caledonia-Norfolk sub-regions, respectively. Industrial electrification projects, new development and intensification contribute to the increase in demand forecast. The Burlington to Nanticoke region is in close proximity, and shares key infrastructure with parts of the bulk power system. This will require coordination between the IRRPs and Central-West Bulk Plan to understand potential impacts of needs or solutions on the regional versus bulk system.

4 Demand Forecasts

This section describes the forecast demand for the Central-West area and the regions of interest. Ontario is becoming a leader in building electric vehicles and batteries, and the automotive sector is growing, with significant new developments from Stellantis in Windsor to Volkswagen in St. Thomas. In addition, Ontario's population is expected to grow by two million people by the end of this decade. As a result, Ontario's electricity demand is rising, especially in the Central-West area, encompassing southwestern Ontario.

The IESO's bulk planning looks at broad areas and growth factors, being responsive to customers and policy decisions. Thus, the growth scenarios considered in this Plan were driven by economic development, policy and governmental direction. The Central-West area is primed for economic development due to a number of factors. Large industrial loads are typically located where they have access not only to electricity, but also to a variety of other factors, all of which can be accessed within the Central-West area. This includes access to a skilled labour force, transportation to efficiently ship their product to serve multiple markets (e.g., Canada and the United States), lands that have been zoned appropriately, supply chain inputs and post-production processing, other utilities (e.g., water, wastewater, gas) and financial resources.

In order for the Plan to respond to these macroscopic factors, the demand forecast and scenario development had to evolve to reflect the unique characteristics of this new type of industrial development (i.e., large, lumpy loads in concentrated areas where the other services they require exist, with preference for low lead times for connection). As part of the process, the IESO engaged with, and received input from, the government on where growth is likely to materialize.

4.1 Growth Scenarios

The 2022 APO forecast was used as the basis to assess various load growth scenarios for the Central-West area, with two blocks of load layered on top – Firm Load in St Thomas and Potential Load in each of the five regions of interest – to create five growth scenarios.

The APO forecast incorporates many factors, including, but not limited to, the state of the economy, population, demographics, technology, energy prices, input fuel choices, equipment-purchasing decisions, consumer behaviour, government policy and conservation. The APO forecast exhibits strong and steady growth through the end of the 2030s, fuelled primarily by industrial sector development in the mid-2020s in mining, steel, EV battery and hydrogen production; agricultural sector greenhouse construction; and transportation sector electrification, before moderating in the early 2040s.

The APO Zonal forecasts for the relevant Zones in 2030 and 2043 are shown in **Table 1**, as it grows over the study period according to the APO forecast.

Table 1 | 2022 APO Zonal, Grid Forecasts (MW)

Station	Summer 2030	Winter 2030	Summer 2043	Winter 2043
West Zone	3,100	3,600	3,400	4,050
Southwest Zone	5,500	5,000	6,300	6,200
Niagara Zone	850	750	1,000	900
Bruce Zone	100	150	100	150

The APO forecast was then combined with two blocks of load: the Firm Load in St. Thomas, followed by the Potential Load in the five regions of interest, identified based on directional information received from the government, municipalities and public stakeholders. Details of the two blocks of load are as follows:

- **Firm Load:** this includes the Volkswagen EV plant in St Thomas, as well as additional ancillary and spin-off loads totalling 620 MW (690 MVA) within the London Area region, which is the assumed base forecast that must be met
- **Potential Load:** this includes 500-650[10] MW of economic development in each of the regions of interest, modelled separately in addition to the Firm Load

Thus, the five growth scenarios have the APO forecast as the basis, with a combination of the Firm Load and one Potential Load, as detailed in **Table 2**.

Table 2 | Growth Scenarios

Growth Scenario	Load Blocks Included
1	Firm Load + Potential Load in the London Area region
2	Firm Load + Potential Load in the Kitchener/Waterloo/ Cambridge/Guelph region
3	Firm Load + Potential Load in the Windsor-Essex region
4	Firm Load + Potential Load in the Chatham-Kent/Lambton/Sarnia region
5	Firm Load + Potential Load in the Burlington to Nanticoke region

Since the Potential Loads are speculative and not directly linked to a specific project, an annual demand forecast was not developed. Instead, a threshold-based approach was used for needs identification, as explained in Section 6.

[10] 650 MW of Potential Load was considered in the London Area region, based on feedback received from the community of higher growth potential in this region and the relative impact it would have on the Firm Load. 500 MW of Potential Load was considered for all other areas.

5 Existing Supply to the Broader Central-West Area and London Area Region

This section describes the supply to the Central-West area and the London Area region specifically, (i.e., to supply the Firm Load), and it outlines the resource scenarios considered to determine the need for additional supply.

5.1 Existing Supply

The Central-West area is supplied by a number of internal wind and gas generation resources, as well as external resources accessed through the existing 230 kV network (connecting the area to the rest of Ontario).[11] The area also encompasses the entire Michigan interconnection, which allows for imports and exports to flow through Sarnia-Lambton and Windsor, and borders the Niagara region, which provides interconnection points with New York.

Specifically looking at the London Area region, it is supplied by four main sources: 1) resources in the West and Southwest Zones, primarily gas-fired generation in Sarnia-Lambton and Windsor-Essex, as well as wind and solar across the Zones; 2) resources in the Bruce Zone via Longwood TS, primarily nuclear and wind; 3) resources in the Niagara Zone, primarily hydroelectric and New York-Niagara interchange; and 4) resources from the rest of Ontario in the east via Middleport TS and Nanticoke TS.

As illustrated in **Figure 8**, there are four main interfaces of interest used to reflect these loads and resources:

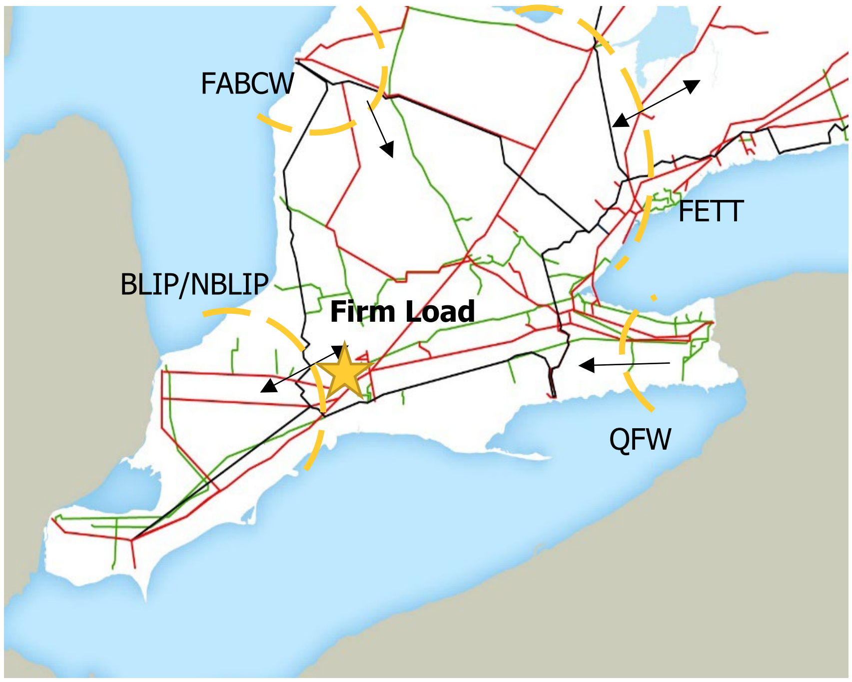
- The **Buchanan-Longwood Input/Negative Buchanan-Longwood Input (BLIP/NBLIP) interface**, consisting of the circuits that connect the West Zone and the Southwest Zone, near the City of London, including three 500 kV circuits into Longwood TS and five 230 kV circuits into Buchanan TS. The NBLIP interface is identical to BLIP, but the power transfer is measured in the opposite direction (i.e., towards the east).
- The **Flow Away from Bruce Complex + Wind (FABCW) interface,** consisting of all the power flow from the Bruce Nuclear Generating Station, including the Bruce 230 kV and 500 kV stations (six circuits each), plus wind generation in the area.
- The **Queenston Flow West (QFW) interface,** consisting of the circuits that connect the Niagara Zone and the Southwest Zone. This includes the four 230 kV circuits out of Beck 2 TS and three 230 kV circuits into Middleport TS.

[11] The mixture of resources used to supply the region's and the province's energy needs at any given time is determined by the real-time energy market.

- The **Flow East to Toronto (FETT) interface,** consisting of the circuits that connect the Southwest Zone and the Toronto and Essa Zones. This includes the four 500 kV circuits into Claireville TS, two 230 kV circuits out of Orangeville TS to Essa TS, and four 230 kV circuits out of Trafalgar TS to Richview TS and Hurontario SS.

Of these interfaces, the most significant source of supply to the Firm Load is through the NBLIP interface, transferring the significant amount of resources from the West Zone, which includes the Sarnia-Lambton area generation.

Figure 8 | Illustration of Key Bulk Interfaces for the Central-West Study*



*These interfaces and load indicators are representative of approximate locations.

5.2 Resource Scenarios

An objective of bulk studies is to identify concerns about the key bulk interfaces within the study area, which are illustrated in **Figure 8**. Preliminary screening indicated that the BLIP/NBLIP interface was the most impacted bulk interface when considering the connection of the Firm Load, specifically, high NBLIP flows, since the Firm Load straddles the BLIP/NBLIP interface. As a result, the immediate focus of the Central-West bulk study was to stress the BLIP/NBLIP bulk flows using the resources within the Southwest and West Zones, based on the following two resource scenarios:

- **Base Generation:** Expected BLIP flow achieved through existing and contracted resources at median contribution to peak, representing the expected contribution of resources to summer and winter peak hour, respectively
- **High Generation:** High NBLIP flow achieved through existing and contracted resources at Installed Capacity (ICAP) for non-renewable generation, and renewables at 10 per cent dependability, representing the maximum expected capability of available resources

Two sensitivities were performed for each case, considering additional imports and exports from Michigan to further stress the NBLIP flow. For the purposes of this study, the two resource scenarios were achieved using existing and planned resources in the West and Southwest to increase the BLIP/NBLIP flow and stress the interface. However, the use of these resources does not imply that they will remain after their contract term. Instead, it was a simplifying assumption to represent a future scenario where a significant amount of resources remain in the West Zone, irrespective of facility or resource type.

Resources in the Bruce and Niagara Zones were held constant, while resources from the rest of Ontario (Essa, Ottawa, East and Toronto Zones) were used as needed to balance any deficit or surplus of generation due to unequal transfers between the main sources above. **Table 3**, **Table 4** and **Table 5** summarize the key interface flows and resource assumptions for the four scenarios considered. Installed capacity is reflective of seasonal capacity and new resources secured through completed procurements.

Preliminary screening did not indicate any issues under high BLIP conditions (i.e., low generation in the West Zone and primary supply from the rest of Ontario into southwestern Ontario). However, further bulk studies will consider an additional low generation scenario, which will incorporate the Powering Ontario's Growth report actions, the new Clean Energy Regulations[12] and/or any relevant policy decisions.

Table 3 | Major Interface Starting Point Flows (MW)

Interface	Summer Base (MW)	Summer High (MW)	Winter Base (MW)	Winter High (MW)
FETL	200	2,300	-100	2,500
FABCW	4,900	5,000	4,900	5,000
QFW	1,900	1,900	1,900	1,900
FETT	1,300	4,000	1,600	5,400

Table 4 | Basecase Resources Assumptions (Summer, 2030)

Zone	Technology	Installed Capacity (MW)	Base Generation (MW)	High Generation (MW)
West Zone	Gas/Steam	3,800	2,000	3,600
	Solar	60	20	50
	Wind	1,500	210	650
	Storage and Other	90	50	90

[12] Low generation assumptions to be developed during subsequent bulk studies. This Plan focused on base and high generation assumptions.

Zone	Technology	Installed Capacity (MW)	Base Generation (MW)	High Generation (MW)
	Total	5,500	2,250	4,400
Southwest Zone[13]	Gas/Steam	830	520	520
	Solar	190	70	170
	Wind	1,600	220	670
	Storage and Other	310	160	290
	Total	2,900	970	1,700
Bruce Zone	Total	7,300	5,200	5,200
Niagara Zone	Total	2,800	2,700	2,700

Table 5 | Basecase Resources Assumptions (Winter, 2030)

Zone	Technology	Installed Capacity (MW)	Base Generation (MW)	High Generation (MW)
West Zone	Gas/Steam	3,800	1,800	3,700
	Solar	100	0	0
	Wind	1,500	700	1,400
	Storage and Other	100	0	100
	Total	5,400	2,500	5,100
Southwest Zone[14]	Gas/Steam	800	500	500
	Solar	200	0	0
	Wind	1,600	300	1,300
	Storage and Other	600	300	500
	Total	3,100	1,100	2,400

[13] Note, Halton Hills CGS is within the Southwest Zone, however, it is outside the Central-West area and so not included in this table.
[14] Note, Halton Hills CGS is within the Southwest Zone, however, it is outside the Central-West area.

Zone	Technology	Installed Capacity (MW)	Base Generation (MW)	High Generation (MW)
Bruce Zone	Total	7,300	5,300	5,300
Niagara Zone	Total	2,800	2,600	2,600

6 Needs Determination

This section describes the assessment of reliability for the Firm Load, and explores key constraints for the Potential Load in the five planning regions of interest. Given that this Plan is primarily focused on the bulk needs arising from the Firm Load in St. Thomas, the most restrictive scenario is Growth Scenario 1 (Firm Load plus Potential Load in the London Area region), coincident with summer peak demand and high generation or high NBLIP flow. The majority of the results in this section will reflect this scenario, with discussion of the preliminary findings for the other growth scenarios in Section 6.4.

6.1 Needs Identification Process

As described in Sections 4.1 and 5.2, for load growth and resource supply scenarios respectively, a number of key sensitivities were considered to determine the magnitude and timing of the need for additional supply capability, including considerations for rate of demand growth, varying levels of local resources, accounting for resources acquired through recent competitive acquisition processes, and interchange capability.

The assessment process was based on transfer analyses, starting with preparing the base case with the forecasted demand in 2030 from the APO, previously recommended transmission reinforcements and resource scenarios. Considering the season and resource scenarios, four cases have been prepared:

Case 1: Summer base generation

Case 2: Summer high generation

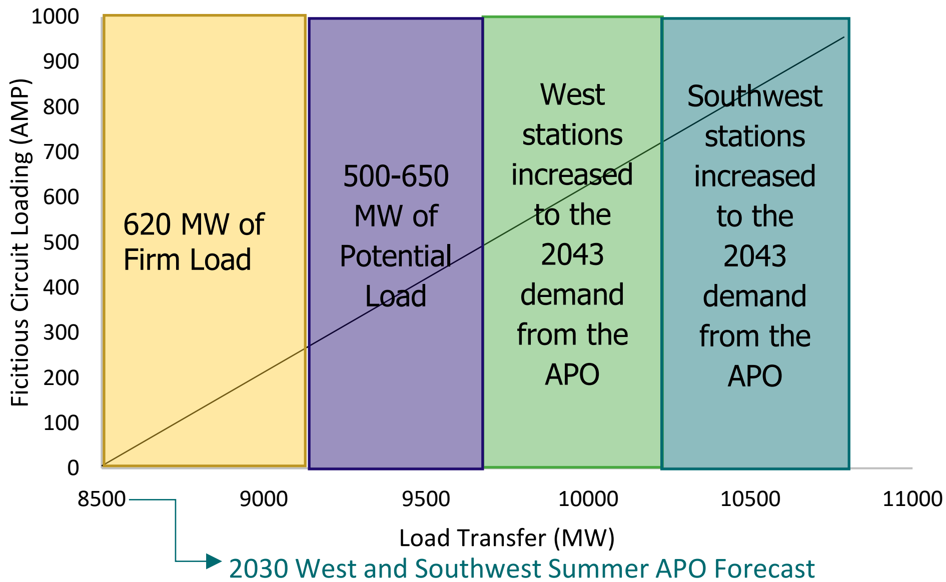
Case 3: Winter base generation

Case 4: Winter high generation

Resources in the West and Southwest Zones were varied based on the resource assumptions in Section 5. While load increases, as per the load transfers outlined in the following paragraph, available resources from the rest of Ontario (i.e., the Essa, Ottawa, East and Toronto Zones) are used to balance any deficit or surplus of generation.

For each of these four cases, five separate load transfers are conducted for each of the five planning regions of interest, as described in Section 3.2. The load transfer steadily increases the case from the starting point (the forecast demand in 2030 from the APO) to the Firm Load (620 MW), then increases one of the five Potential Loads in southwestern Ontario (500-650 MW), and finally increases the remaining stations to match the forecast demand in 2043 from the APO. Refer to **Figure 9** for an illustrative example of the load transfer.

Figure 9 | Illustrative Graph of Load Transfer



In order to assess reliability impacts, there are two key questions:

1) can the bulk supply lines accommodate the additional load?
2) what is the impact to the interface capability to deliver resources to the province?

Question one identifies a supply capacity need, while question two explores congestion and the potential impact on economic dispatch. To address violations to the transfer capabilities or system capabilities, wires and non-wires options are developed and evaluated to resolve the violations. To understand the impact to the interface deliverability, sensitivities were conducted with the addition of imports/exports from Michigan to further stress the NBLIP interface. This would identify any limitations transferring resources needed to supply load out of the West Zone, as well as any congestion. Congestion needs are not a transmission security violation, but rather identify potential economic benefit to all.

Typically for electricity planning, a specific year is identified as the need year, meaning that at that year, the existing transmission system is incapable of supplying the forecast demand and a solution is needed. Given the uncertainty of the Potential Load considered in this Plan, instead of identifying a need year, a load threshold approach was used. The capability of the existing system was identified and the need defined based on the amount of load that needs to materialize in a location. When customer commitments for the area reach the load threshold, the conditional plans identified in this Plan should be implemented.

Planning criteria were applied in accordance with NERC standards and the NPCC reliability directories to determine system capacity needs.[15] In the context of the bulk system, adequacy (i.e., system need) is defined as the ability to supply demand at all times, while respecting transfer capability limits across the bulk system and interconnections and taking into account scheduled and reasonably expected unscheduled outages of system elements.[16]

This assessment assumed that the recommendations of the 2021 West of London Bulk Report and 2019 Windsor-Essex bulk study were implemented (i.e., a transformer station in Lakeshore (Lakeshore TS) and a new double circuit 230 kV line between Lakeshore and Chatham (the Chatham west lines), a new double circuit 230 kV line between Lambton and Chatham, and a new single circuit 500 kV line between Longwood and Lakeshore (LxH) are in place). Thus, the 2030 transmission system and demand forecast were used as the basis of the analysis presented in this section.

The following sections outline the supply capacity, congestion, and other considerations identified resulting from this analysis. Note, not all cases resulted in identified needs, and only those that did are discussed.

6.2 Supply Capacity Need

Firm Load is directly connected to circuits comprising the NBLIP interface.

The NBLIP transfer capability is important for delivering supply from the West Zone to the Southwest Zone (in which the London Area region is located) and the rest of the province. This includes the output of generation and Ontario-Michigan imports in the Sarnia-Lambton area, as well as load in the Windsor-Essex region and Chatham-Kent area.

Study results found that the NBLIP transfers were thermally limited by circuits between Buchanan and Middleport, located east of where NBLIP is measured. The Firm Load directly connects to these circuits, which are on the NBLIP interface, and that connection is reducing the capability of those circuits to deliver planned and existing resources in the west. This is a security violation, and so a solution is needed.

Since it is recommended that the Firm Load should be connected to M31W+M33W,[17] which has a lower transfer capability than M32W+M33W, there is a supply capacity limitation identified after the majority of the Firm Load (600 MW) is connected. In addition, due to the sheer amount of load being added to the London Area region, voltage collapse concerns are also identified. The most limiting results for the summer Case 1 and Case 2 are stated in **Table 6**, which illustrate the main supply constraints.

[15] Refer to Appendix A for details on the planning assessment criteria.

[16] Based on NERC's Reliability Terminology, https://www.nerc.com/AboutNERC/Documents/Terms%20AUG13.pdf.

[17] Refer to Appendix C for assessment of Firm Load connection configuration.

Table 6 | Supply Capability with Growth Scenario 1 (Firm Load + Potential Load in the London Area region), Summer

Case	Element(s) out of Service	Additional Supply Capability (MW)	Limitation	Limiting Contingency	Limiting Element
2	None	600	Thermal	M32W+M33W	M31W Buchanan TS to Firm Load tap
1,2	None	900	Low Voltage, Voltage collapse	M31W+M33W, M32W+Q25BM	Ingersoll TS

As a result, the following concerns were identified, to be addressed in this Plan:

- Unacceptable impact to the transfer capability of the NBLIP interface as 600 MW of major economic development is added in the London Area region, on top of forecast annual growth, resulting in thermal constraints on M31W between Buchanan TS and the project tap (i.e., where the Firm Load connects to the bulk transmission system)
- Voltage concerns as approximately 900 MW of major economic development is added, resulting in low voltage and voltage collapse at Ingersoll TS, due to the amount of load being supplied via one Middleport TS to Buchanan TS (MxW) circuit

The evaluation of options to address the M31W thermal limitation, or supply capacity need, is presented in Section 7, which will address the reliability concern.

To address the voltage collapse concern, dynamic, rather than static, voltage devices are required, to provide rapid response to system conditions and prevent cascading effects. Based on the assumptions of the Potential Load location, Ingersoll TS was identified as the best connection point for the voltage device. However, given that this is a long-term need, recommendations are conditional on load materializing, which will determine the optimal placement of such a device.

6.2.1 Pre-2030 Sensitivities

For Case 2 (Summer high generation), sensitivities were conducted considering the period 2028 to 2030, based on the reinforcements in-service:

1. **Post-2030:** with all recommended transmission reinforcements in-service, including the Longwood to Lakeshore 500 kV line (LxH), Lambton to Chatham (LxC), and Lakeshore to Chatham reinforcements in-service
2. **Pre-2030:** with only the Lambton to Chatham (LxC) and Lakeshore to Chatham reinforcements in-service
3. **Pre-2028:** with only the Lakeshore to Chatham reinforcement in-service

Figure 14 illustrates that prior to 2028, there will be approximately a seven and a half per cent to three per cent thermal overload on N21W without both the Longwood to Lakeshore 500 kV line and Lambton to Chatham 230 kV double circuit reinforcements for Case 2. The thermal overload occurs with the addition of approximately 450 MW of load, which is above the confirmed Volkswagen (VW) load. This risk needs to be managed for additional spin-off loads considered as part of the Firm Load. There are operational actions that can be utilized in the near-term, including the consideration of operational ratings, which are generally higher than planning ratings. The IESO will continue to monitor how spin-off loads and other loads materialize and the progress of the recommended transmission reinforcements, to assess the need for interim operational actions prior to 2030.

Figure 10 | Sensitivities to N21W Pre-contingency Loading without Reinforcements

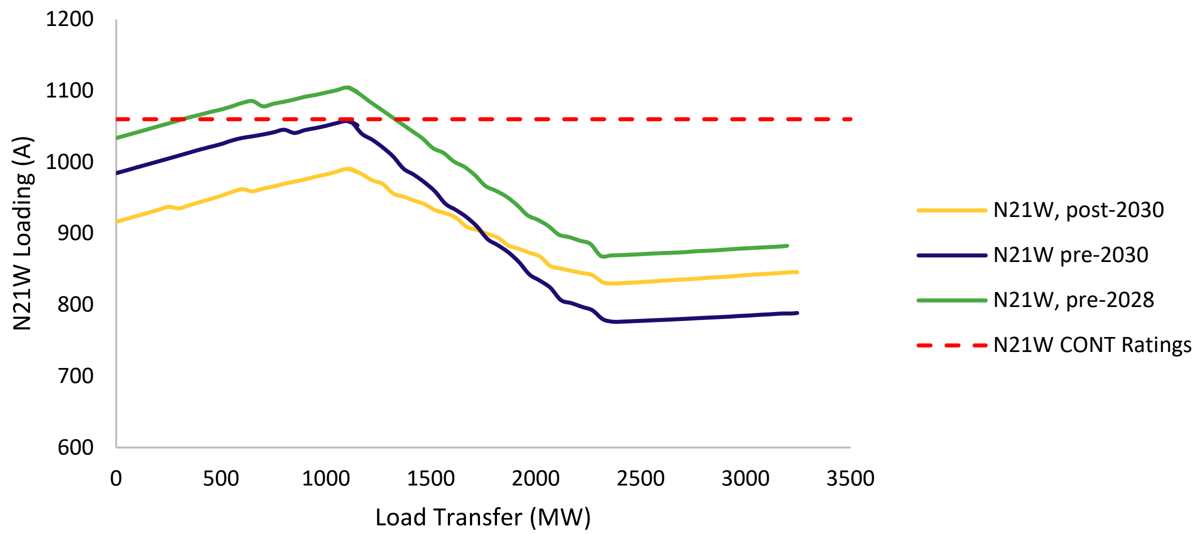
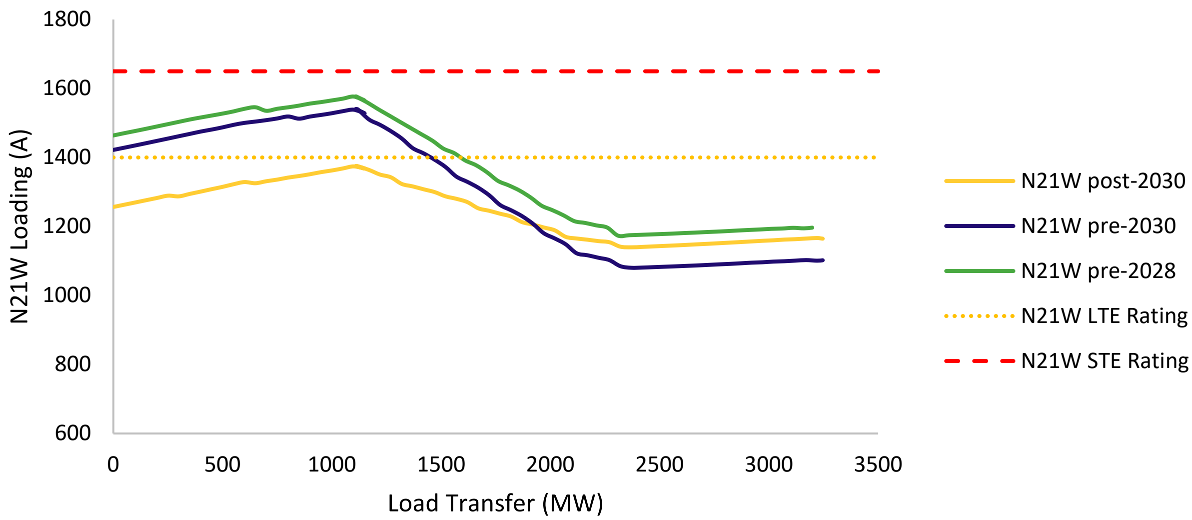


Figure 15 shows that considering the period 2028 to 2030, there are thermal violations prior to the LxH being in-service, with respect to the LTE rating. However, these are eliminated when applying the STE rating, as allowed per ORTAC.

Figure 11 | Sensitivities to N21W Post-Contingency Loading without Reinforcements



6.3 Congestion Need

In addition to meeting established criteria and standards, the IESO also seeks to enable economic efficiency, such as reducing losses and congestion, and facilitating intertie/trade requirements. Supply capacity and congestion needs are differentiated as described below.

A supply capacity need exists when projected flows across a bulk interface exceed the transfer capability under the assumed growth and resource scenarios considered. This results in insufficient supply to meet projected demand, as identified for the NBLIP interface in the previous section. Supply capacity needs, also referred to as "security" needs, are typically based on a snapshot of peak demand conditions. In a situation where generation capacity shortfalls are projected for the province and/or Zone as a whole, a security need may also emerge if firm sources of capacity are bottled and non-deliverable to load centres. Note that firm sources of capacity in this context refers to contracted generation/storage, intermittent resources discounted to reflect their expected contribution in peak demand conditions, and firm imports.

On the other hand, congestion is the condition under which the energy trades that market participants (such as generators and importer/exporters) wish to implement exceed the capability of the IESO-controlled grid.[18] Congestion needs are typically based on hourly energy simulations to forecast flows across interfaces based on demand, resource availability, economic resource dispatch, and intertie energy transactions.

There are several control actions that the operator can take to reduce congestion, such as changing reactive dispatch, arming RASs, and manually constraining generation and electricity storage up or down. Thus, per Ontario Resource and Transmission Assessment Criteria (ORTAC) Section 4.1, which provides information on transfer capability degradation criteria, new or modified connections to the IESO-controlled grid may increase congestion on transmission facilities, but are not permitted to lower power transfer capability or operating security limits by five per cent or more.

[18] As defined in ORTAC, Section 4.6.

This section details the analysis that was conducted using imports to further stress the interface flows to identify any congestion concerns. First, it is established that the Firm Load does not reduce the transfer capability of critical interfaces by more than five per cent. Beyond the supply capacity need, the next limitation is seen on the Nanticoke TS to Buchanan TS (NxW) circuits. However, with respect to the application of the five per cent transfer capability degradation criteria, the NBLIP interface is not the appropriate bulk transmission interface, rather the Flow East Towards London (FETL) interface is more appropriate. Analysis of the FETL interface found that Growth Scenario 1 is not expected to result in more than four per cent degradation of the bulk interface.

Second, it is shown that while the Firm Load and Potential Load do increase congestion, the impact is minor. Analysis of the impact of imports to further stress the flow east found that while Growth Scenario 1 increases congestion, this is not expected to occur more than two per cent to four per cent of the time, based on projected flows for the APO Case 2 Ontario-only and multi-area models respectively. This represents an incremental increase of one and a half per cent to three per cent relative to without the Growth Scenario. This is not expected to be a concern for provincial energy needs, due to the marginal impact relative to the significant amount of load considered and since non-firm imports are required to reach the higher end of this range, based on the best available information of resources in the West Zone at this time. Instead, this translates to a lower ability to trade over system peak demand.

6.3.1 Transfer Capability Degradation

It was determined that the NBLIP interface is not the appropriate bulk transmission interface to assess transfer capability degradation due to the load increase in London. FETL measures the ability to transfer or export power from the West of London area to the London Area region, where a strong transmission hub exists to transmit this power to the rest of the Ontario grid (Longwood TS), and is, hence, the more appropriate transmission interface to apply the transfer capability degradation criteria of no more than five per cent. Refer to **Table 7** for the definitions of NBLIP and FETL. FETL was similarly used to determine the need for the Lambton to Longwood Transmission Upgrade Project in 2012, in order to enhance deliverability of system resources.

Table 7 | Interface Definitions

Interface	Inteface Name	Definition
NBLIP	Negative Buchanan-Longwood Input	N582L, B562L, B563L, M31W, M32W, M33W, D4W, D5W measured at Buchanan TS and Longwood TS
FETL	Flow East Towards London	N21W, N22W, L24L, L26L, W44LC, W45LS, new Longwood to Lakeshore 500 kV circuit

Under the high generation scenario with the import sensitivity, with an FETL flow of 2,700 MW and all previously recommended reinforcements in-service, without the Firm Load, up to 500 MW of imports can be achieved before reaching a pre-contingency thermal limitation on the NxW circuits. As shown in **Table 8**, with the Firm Load, under the same generation conditions, and an FETL flow of 2,600 MW, up to 330 MW of imports can be achieved, resulting in a degradation of four per cent.

Table 8 | Impact of the Firm Load on Key Interfaces

Interface	Flow without Firm Load (MW)	Flow with Firm Load (MW)	Degradation (%)
FETL	2,700	2,600	-4
Michigan Imports	500	330	n/a

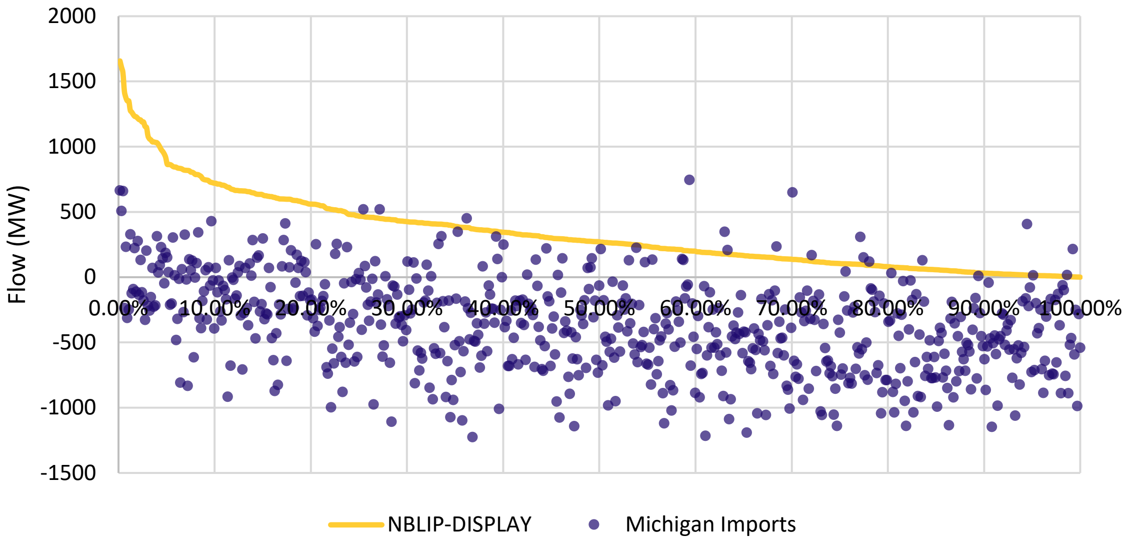
6.3.2 Congestion Assessment

While the true congestion phenomena is on the FETL interface, the results of this section still reference NBLIP flows, since IESO's energy simulations are set up to monitor NBLIP. NBLIP and FETL flows are highly correlated – both interfaces measure bulk flow from the West Zone eastwards, but differ in the specific circuits and points at which the measurement is taken. The FETL congestion limitation correlates to an NBLIP flow of 1,300 MW with the Firm Load. In other words, achieving an NBLIP flow greater than 1,300 MW would require full dispatch of West Zone resources coincident with 330 MW of imports and peak load.

Based on historical and projected flows on the NBLIP interface, there is limited need to maintain NBLIP flows above 1,300 MW. These results are based on the APO Case 1, which assumes that resources are not maintained once their contract expires. There is sufficient bulk transfer capability across the NBLIP interface to deliver existing and planned resources west of London. Instead, this limitation indicates that it is not possible to transfer the full capability of western generation and full Michigan imports at the same time as Ontario demand is peaking. Thus, the need to maintain full NBLIP capability would be more dependent on how much new generation is sited in the West Zone and is therefore a congestion need, not a security need.

Over the last five years, NBLIP flows have exceeded 1,300 MW approximately one per cent of the time.

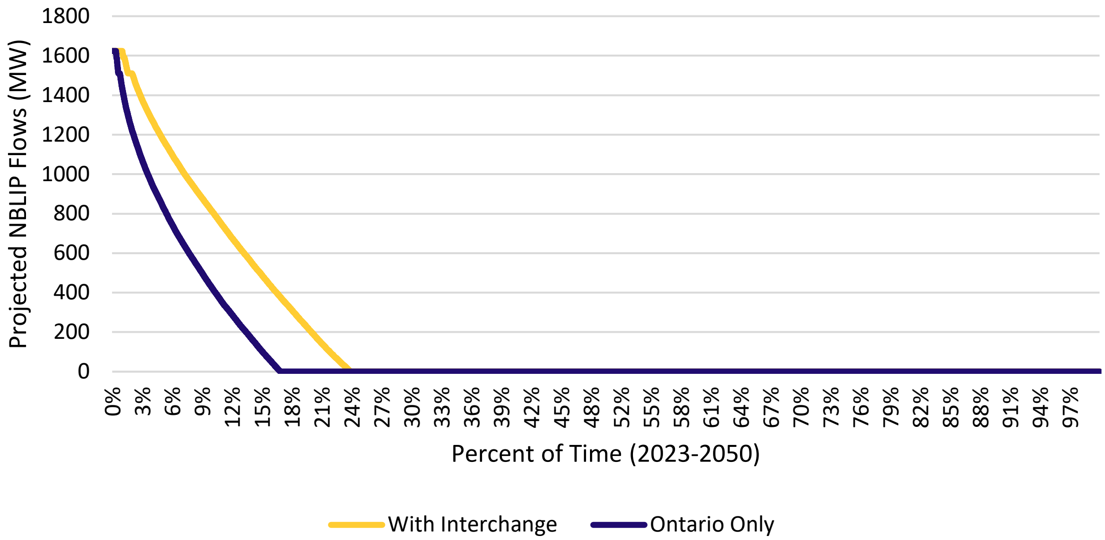
Figure 12 | Historical NBLIP Duration Curve with Michigan Imports, 2018-2022



Based on the 2024 APO energy models,[19] considering the Ontario-only model, NBLIP flows are only projected to exceed 1,300 MW two per cent of the time (between 2023 and 2050). NBLIP flows greater than 1,300 MW are seen in the Ontario-only energy models when demand in the West Zone is lower than the peak values assumed in the congestion studies. Considering the multi-area model with interchange, NBLIP is projected to exceed 1,300 MW four per cent of the time (see **Figure 13**). Without the Firm Load, flows are expected to exceed the NBLIP flow of 1,600 MW, which correlates to the FETL flow without the Firm Load, approximately a half per cent to one per cent of the time. This results in a one and a half per cent to three per cent increase in congestion due to the addition of Firm Load.

[19] APO Case 2 forecast, which assumes that resources continue to be available post-contract/post-commitment expiry for the duration of the study period, consistent with the resource scenario assumption, to represent the worst case scenario.

Figure 13 | Projected NBLIP Duration Curve



6.4 Future Considerations

The impact of the Firm Load plus Potential Load in the London Area region was found to be compounding (i.e., Potential Load in the London Area region has the greatest impact to the phenomena limiting supply to the Firm Load). As such, this Plan focused on Growth Scenario 1 (Firm Load + Potential Load in the London Area region). This section describes the findings for the other growth scenarios considering the 2022 APO forecast in 2030, as well as further bulk or regional studies that may be required to assess the potential needs and options.

On July 10, 2023, the Ministry of Energy released the POG report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. The Ontario government is planning the electricity infrastructure for a more electrified Ontario, where economic growth continues to drive new jobs and emissions continue to be reduced. The South and Central Ontario bulk planning study being initiated this year will consider the impact of the objectives of the POG report across southwestern Ontario. The Central-West report identifies linkages and potential reliability concerns, which will be integrated with POG objectives to better plan for potential linkages and their cumulative impact, as detailed in the following sections.

6.4.1 Growth Scenario 2

Preliminary studies considering Growth Scenario 2 (Firm Load + Potential Load in the Kitchener-Waterloo/Cambridge/Guelph region) indicate that thermal limitations are seen on the transmission paths between Detweiler TS and Orangeville TS, as well as the 115 kV path between Burlington TS and Detweiler TS. This is seen both pre-contingency and under outages to a Middleport TS to Detweiler TS circuit, a Detweiler TS to Orangeville TS circuit, or two Bruce to Longwood TS circuit outages. However, these limitations are independent of the Firm Load or Potential Load in the London Area region. Thus, no firm recommendations are made at this stage. This should be monitored and inform the South and Central Ontario bulk planning study and the next cycle of regional planning.

Low voltage and eventual voltage collapse at Preston TS was identified after approximately 1,110 MW of load is added under Growth Scenario 2. Additional reactive support may be needed at Buchanan TS or closer to Preston TS. With an outage to a Detweiler TS to Orangeville TS or a Middleport TS to Detweiler TS circuit, this concern is triggered earlier. However, this is a local limitation, not directly linked to the Firm Load, and so should inform the next cycle of regional planning.

6.4.2 Growth Scenario 3

Preliminary studies considering Growth Scenario 3 (Firm Load + Potential Load in the Windsor-Essex region) indicate a correlation between Potential Load in this region and Potential Load in the London Area region. With higher load in the west, under Growth Scenario 1, there is less flow east on the FETL or NBLIP interface. Thus, there is a balance between the addition of load or resources in this region with load or resources in the London Area region, with respect to maintaining the bulk transfer capabilities. Subsequent bulk and regional plans will monitor the impact of load growth in this region on the NBLIP congestion identified.

Hydro One is currently undertaking early development work on a second 500 kV line between Longwood TS and Lakeshore TS. This Plan reaffirms that the need for this line is conditional on additional load materializing in the Windsor-Essex region. Subsequent bulk and regional plans will monitor the impact of load growth in this region on the need for this reinforcement, as loads materialize.

In addition, considering Potential Load in the Windsor-Essex region in combination with the West of London forecast for agricultural growth in the region, there is a need for additional voltage support. This need is seen especially during the winter, when the Potential Load coincides with peak agricultural load. This voltage concern should inform the ongoing Windsor-Essex IRRP, when considering high regional demand.

6.4.3 Growth Scenario 4

Preliminary studies considering Growth Scenario 4 (Firm Load + Potential Load in the Chatham-Kent/Lambton/Sarnia region) indicate the same correlation to Potential Load increases in the west of London area, as seen in the Windsor-Essex region. Higher load in the west of London area results in less congestion on the FETL or NBLIP interface, as resources supply the Windsor-Essex and Chatham-Kent/Lambton/Sarnia regions within the West Zone, thus reducing the flow out of the Zone towards the London Area region. Thus, there is a balance between the addition of load or resources in these two regions with load or resources in the London Area region, with respect to maintaining the bulk transfer capabilities. Subsequent bulk and regional plans will monitor the impact of load growth in this region on the NBLIP congestion identified.

While this Plan considered economic development in each of the five regions of interest, growth in Sarnia-Lambton is more accurately considered in terms of net load. There is an existing generation source and further changes to the resource mix resulting from the POG report or the proposed federal Clean Electricity Regulations would net out some or all load increases in this pocket. As a result, considering the net impact of generation and load will increase the range of scenarios to be considered in subsequent South and Central Ontario bulk studies to support the POG report.

6.4.4 Growth Scenario 5

Considering Growth Scenario 5 (Firm Load + Potential Load in the Burlington to Nanticoke region), no bulk concerns are anticipated with additional Potential Load, since there is robust supply in this region. However, changes in the supply mix in southwestern Ontario, as contemplated in the POG report, will impact the characteristics of the area, which will inform subsequent South and Central Ontario bulk studies to support the POG report.

7 Options Evaluation and Recommendations

Section 5 indicated that there was an unacceptable impact to the transfer capability of the NBLIP interface. This resulted in:

1. Thermal constraints on the M31W supply circuit to the tap point of the Firm Load
2. Voltage concerns needed to maintain the capability of bulk system interfaces, while supplying the Firm Load and additional load in the London Area region

This section details the assessment of options to address this need and recommends the most effective solution to maintaining supply for future loads in the area.

7.1 Options Analysis

To determine the most cost-effective way to relieve the unacceptable impact to the transfer capability of the NBLIP interface, the following options were considered to address the thermal limitation identified:

- **Option 1: Reinforce the existing transmission supply circuit.** This option considers the reinforcement of the supply circuit, M31W, between Buchanan TS and the Firm Load tap point. The 2-5 km transmission line would maintain the capability of the bulk system while increasing the supply transfer capability by 300 MW.[20]
- **Option 2: Local resources.** In this option, the identified capacity and energy needs are met through the addition of the least-cost, non-emitting resource alternative, located between the Firm Load tap point and the Firm Load. This analysis included additional resources capable of increasing the supply capability by 300 MW, with two sensitives for how load may grow:
  - Sensitivity A: Resources are staged in with an assumed gradual ramp up over five years to meet incremental load requirements
  - Sensitivity B: The full amount of resources are in-service from the start of the need, paralleling the transmission reinforcement supply

Both options increase the supply capability by 300 MW, which addresses the last 20 MW of the Firm Load and a significant portion of the next pocket of Potential Load considered in the London Area region.

In Option 1, the transmission reinforcement has the potential to provide additional transfer capability, but is constrained by voltage limitations.

[20] The transmission option can provide a total of approximately 450 MW of transfer capability based on thermal constraints, however, it is limited to 300 MW by voltage concerns. Voltage support is required to achieve the full transfer capability improvement.

Option 2 was evaluated considering cost benchmarks based on non-emitting resource types capable of supplying the magnitude of energy and capacity required – new wind in combination with a new battery energy storage system (BESS).[21]

Other wires and resource options, including a new switching station, wind, solar, biomass and a small nuclear reactor were considered as potential cost benchmarks for the analysis, but were screened out or determined to be incapable of meeting the need due to technical limitations or long lead times. Other non-wires options, such as energy efficiency, distributed generation, and demand response were also considered, but were screened out as unsuitable due to the magnitude, location and uncertainty of the growth. Conservation and demand management options are more likely to be feasible if the need is roughly less than two per cent of the total demand forecast for each year. For this Plan, an annual forecast was not developed due to the uncertainty of the load growth, but 300 MW is roughly 30 per cent of the total load added (620 MW of Firm Load and 300 MW of Potential Load), indicating that this option is not feasible. In contrast, the feasibility of distributed generation options is limited by the available connection space at each transformer station. Distribution generation resources would need to be connected to the tap connection, which would not have the connection capacity space to accommodate 300 MW of distributed generation. Similarly, demand response is limited to the loads connected to the tap point, which are assumed to be very large industrial loads that are generally not demand-responsive, but require constant supply to maintain their industrial processes. However, the planned energy efficiency and use of existing distributed energy resources were incorporated into the demand forecasts.

7.1.1 Cost Considerations

Comparing the required transmission reinforcement to the resource alternative, the transmission reinforcement results in a net present value (NPV) cost saving of approximately $4 billion to $17 billion. The impact of a gradual ramp rate (Sensitivity A vs B) was negligible, compared to the impact of resource costs and capacity benefit, which drove the range in cost savings seen in **Table 9**.[22]

For Option 1, the capital cost of transmission was assumed to be $9 million to $40 million, based on a range of circuit costs. The NPV accounts for the system energy costs required to supply the 300 MW of additional load that is otherwise supplied by the new resource in Option 2.

Table 9 | Net Present Value Comparison of Option 1 and 2 ($B)

Option	Description of Option	Cost ($B)
1	M31W reinforcement between Buchanan TS and Firm Load tap	3
2	Combination of Wind and BESS Resources	7-20

[21] The ultimate resource type may be subject to subsequent competitive procurements, as required.

[22] Refer to Appendix B for details on the resource cost and capacity benefit assumptions.

The hourly energy profiles for both the Firm Load and Potential Load were assumed to follow a typical industrial load profile, which is relatively constant in terms of business days through the year, with roughly 15 per cent variability between peak and off-peak periods. Due to the sustained periods of energy need, approximately 2,800 MW of wind resources and 300 MW (1,800 MWh) of BESS was needed for the Option 2 resource alternative, making it prohibitively expensive.

These results indicate that transmission reinforcement is the most cost-effective option.

7.1.2 Resource Considerations

Aside from providing energy, acquired supply resources under Option 2 could provide additional benefits to the system through reliability services (e.g., operating reserve) and system capacity value to supply provincial needs.

Historically, a gas-fired turbine has been the pricing benchmark for new resources in Ontario. However, the potential for local opposition to new gas generation facilities and proposed regulations restricting emissions from electricity generators render gas-fired turbines higher risk. Therefore, a gas-fired turbine was not considered for this assessment.

For a resource to meet the need described in Section 5, it must be located at the Firm Load tap point, or between the tap and the Firm Load supply station. Ideally, the generation would be directly connected to an integrated transmission station, which means either it connects at the Firm Load supply station or a new station is built. It must also be capable of providing a significant energy component, along with the required capacity, since industrial loads are assumed to have a generally constant energy need throughout the day.

Approximately 2,800 MW of wind, in combination with 1,800 MWh of storage, would be required to meet the need. This amount of wind is roughly half of Ontario's existing installed wind capacity. In addition, a significant amount of land would be needed to site all required wind in close proximity to the tap point – approximately 850 hectares. Such a large volume of resources creates untenable supply chain, project cost, and timeline risks. In addition, as this is a location-specific need, it would be unlikely to be met through provincial procurements.

7.1.3 Transmission Considerations

The transmission option would require rebuilding the towers between Buchanan TS and the tap to accommodate higher capacity conductors. M31W was previously reinforced to accommodate the largest single conductor size used by the transmitter (Hydro One). As such, the M31W towers are smaller than M32/33W, and are limited by clearances and span lengths. Thus, increasing the conductors on M31W with the existing towers would not increase the transfer capability, to maintain the required clearances for farmland and farm equipment. To reinforce M31W, the transmission line would need to be rebuilt with new towers.

The option of building a switching station at the Firm Load tap point was considered to sectionalize and connect the three MxW circuits. While this would balance the flows across the three supply circuits and provide some voltage support, thermal constraints on M31W are still the limiting phenomena, and so this does not address the supply need. In addition, the high-level cost for this option is $175 million to $200 million, at least five times greater than the transmission reinforcement option.

The current Buchanan TS is space limited in terms of adding additional circuits beyond one element, as well as regarding egressing the station, due to the station configuration and location adjacent to Highway 401. Since there is space at Buchanan TS to terminate one more circuit, the option to construct a new 230 kV circuit from Buchanan TS to the tap was considered. However, in order to connect the new circuit to the Firm Load, a switching station would be needed, making this option cost prohibitive.

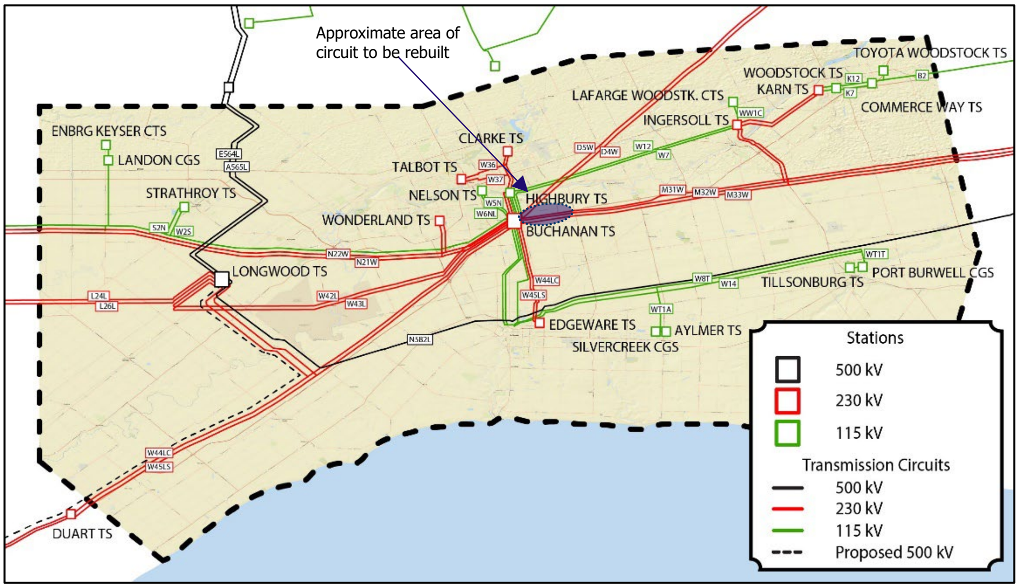
While rebuilding the towers between Buchanan TS and the tap provides additional transfer capability, further reinforcements will eventually be necessary to support future load growth. Depending on where further load materializes and how the transmission system evolves, extending the scope of the rebuild of M31W or adding an additional circuit between Buchanan TS and Middleport TS could be required. Since the preferred option is to reinforce the transmission line and rebuild the towers, an assessment was conducted to consider whether double circuit towers (i.e., towers that can carry two circuits) should be used to accommodate future potential circuits along this path. The planning estimate for double circuit towers is roughly the same as that of single circuit towers, given the margin of error of high-level costs. This would leverage the one remaining termination available at Buchanan TS and allow for the tower construction, without needing to first remove M31W from service. Importantly, this would preserve the option to quickly add a second circuit if/when it is required. The second circuit would further increase the transfer capability across the London Area region, while maintaining load security. Thus, it would be prudent to reconstruct the section between Buchanan TS and the Firm Load tap with double circuit towers, considering the marginal cost difference and potential long-term benefits.

7.2 Recommendations

Based on the analysis presented in this section, the IESO recommends rebuilding the supply circuit, M31W, between Buchanan TS and the Firm Load tap point with double circuit towers strung with one circuit (see **Figure 16**). This preserves the option for a future additional 230 kV circuit to continue to supply the area, depending on where and when further load growth materializes. It is recommended that this work begin immediately, assuming a five-year lead time for implementation.

Dynamic voltage devices are also needed across the area as load grows and, in particular, at Ingersoll TS if more than 300 MW of Potential Load materializes in the London Area region.

Figure 14 | Approximate Location of Circuit to be Rebuilt



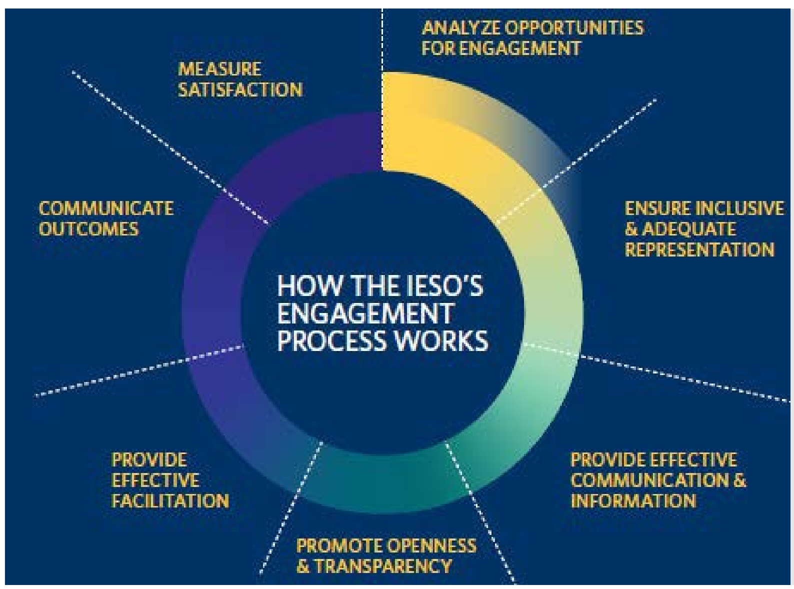
8 Community and Stakeholder Engagement

Engagement is critical in the development of an electricity plan. Providing opportunities for input in the regional planning process enables the views and perspectives of the public, which for these purposes, refers to market participants, stakeholders, communities, First Nations and Métis peoples, customers, and the general public, to be considered in the development of the Plan, and helps lay the foundation that helps inform its decision-making. This section outlines the engagement principles and activities undertaken for the Central-West Bulk Plan.

8.1 Engagement Principles

The IESO's engagement principles (see **Figure 17**) help to ensure that all interested parties are kept informed. They also enable opportunities for purposeful engagement to contribute to electricity planning initiatives, such as the development of this Plan. The IESO adheres to these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 15 | The IESO's Engagement Principles



8.2 Engagement Approach

To ensure that the Plan reflects the needs of market participants, stakeholders, communities, First Nations and Métis peoples, customers, and the general public, engagement involved:

- Leveraging the Southwest Bulk Planning Initiatives webpage and Central-West Bulk Planning engagement webpage on the IESO website to post updated information, engagement opportunities, meeting materials, input received and IESO responses to the feedback
- Communication with communities, stakeholders and interested parties through email, Southwest Regional Electricity Network updates, and the IESO weekly Bulletin

- Public webinars
- Targeted outreach throughout plan development with municipalities, customers, and those with an identified interest in southwest Ontario electricity issues

Two public webinars were held at major junctures during plan development to give interested parties an opportunity to hear about its progress and provide comments on key components including:

- Electricity demand growth scenarios
- Identified needs
- Options evaluation
- Recommendations

Both webinars received strong participation with stakeholders in attendance, and resulted in the submission of written feedback during the two-week comment periods.

Engagement was instrumental in garnering feedback about expected economic development across southwestern Ontario being driven by high industrial growth, as well as increased growth in residential and commercial developments. Comments received during this engagement focused on the following major themes:

- Alignment and coordination with other municipal and community planning, local developments, growth plans and the impact of decarbonization is needed. Future infrastructure and/or electricity supply should consider the priorities of energy and climate action plans and, in particular, alternative energy systems, renewable generation, electrification and climate resilience.
- Consideration should be given to non-wires alternatives, such as distributed energy resources and demand side solutions, as part of the recommended solutions.
- Concern around potential delays in needed electricity infrastructure to enable investments and economic development should be considered.
- Integrated options that provide both local and broader provincial system benefit should be considered.
- Shifting economies, in particular for different resource technologies, should be incorporated into planning assumptions and cost benefit analysis.
- Integration with other IESO regional and bulk planning activities, Annual Planning Outlooks, energy procurements, and governmental policy and directives should be carried out.

Based on the discussions about both the Central-West Bulk Plan and parallel Windsor-Essex regional planning initiative, it is clear that there is broad interest in several southwestern Ontario communities to further discuss the potential for solutions that fully utilize existing transmission infrastructure and minimize the footprint of solutions.

The feedback received helped to guide further discussion throughout the development of this Plan and add due consideration to the final recommendations.

All background information, including the engagement plan, engagement meeting presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Central-West bulk planning engagement webpage.

8.3 Bringing Communities to the Table

The IESO informed municipalities and key stakeholders of the development of this Plan and recommendations. The IESO was available to discuss and address any key issues of concern and options for meeting those future needs.

8.4 Engaging with Indigenous Communities

To raise awareness about the bulk transmission planning activities underway in Ontario for 2024 and provide an overview of the Central-West Bulk Plan, outreach was offered to all Indigenous communities in Ontario. They were invited to attend a targeted meeting in April 2024 to provide an opportunity shape how engagements are approached for bulk transmission studies going forward. Those invited to participate, who are within southwestern Ontario, include the communities of Saugeen Ojibway First Nation, Nawash First Nation, Chippewas of the Thames First Nation, Mississaugas of the New Credit, Six Nations of the Grand River, Haundenosaunee Confederacy Chiefs Council (HCCC), Haundenosaunee Development Institute (HDI), Aamjiwnaang First Nation, Bkejwanong (Walpole Island First Nation), Métis Nation of Ontario, Chippewas of Kettle and Stony Point, Caldwell First Nation, Oneida Nation of the Thames, Munsee Delaware and Moravian of the Thames.

The IESO remains committed to ongoing and meaningful engagement with Indigenous communities, to help shape long-term planning in regions all across Ontario.

8.4.1 Indigenous Participation and Engagement in Transmission Development

The IESO determines the most reliable and cost-effective option and publishes those recommendations in the applicable regional or bulk planning report. Where the IESO determines that the lead time required to implement recommended solutions requires immediate action, the IESO may provide those recommendations ahead of the publication of a planning report, for example, through a handoff letter to the lead local transmitter in the region.

As part of the overall transmission development process, a proponent applies for applicable regulatory approvals, including an Environmental Assessment that is overseen by the Ministry of Environment, Conservation and Parks (MECP). This process includes, where applicable, consultation regarding Indigenous and treaty rights, and approvals may include measures to avoid or mitigate impacts on said rights. MECP may delegate the procedural aspects of consultation to the proponent while maintaining oversite into those delegated aspects and the consultation process generally. Following development work, the proponent will then need to apply to the OEB for approval through a Leave to Construct hearing, and only if approval is granted, can it proceed with the project.

In consultation with MECP, project proponents are encouraged to engage with Indigenous communities and rights-holders on ways to enable participation in these projects.

9 Conclusions and Recommendations

This document describes the Plan that has been developed for the Central-West bulk study, and recommends measures to ensure continued, reliable supply to the Firm Load in the London Area region. This Plan has been coordinated with regional plans, including the ongoing Windsor-Essex and Burlington to Nanticoke IRRPs.

The bulk study recommends immediately reconstructing the M31W circuit between Buchanan TS and the Firm Load tap point (approximately 2-5 km in length), assuming a five-year lead time. This will relieve the unacceptable impact to the transfer capability of the NBLIP interface and allow the connection of approximately 300 MW of Potential Load in London Area region beyond the Firm Load. Furthermore, it is recommended that the new M31W towers be rebuilt as double circuit towers, strung with one circuit but capable of accommodating a second circuit in the future, if/when needed. This would preserve the option to quickly increase the transfer capability across the London Area region even further, if the Potential Load location or amount shifts from the assumptions in this Plan. Since this recommendation is to reconstruct the existing transmission infrastructure, it is expected that the incumbent transmitter would be in the best position to proceed with this work.

Dynamic voltage devices are also needed across the area as load grows, and in particular at Ingersoll TS if more than 300 MW of Potential Load materializes in the London Area region.

For the recommended transmission solutions, the next steps would include the transmitter proceeding with development work, including applicable regulatory approvals, before proceeding with implementation and construction.

The IESO, along with the relevant distributors and transmitters, will continue to monitor the load growth, progress of developments toward plan deliverables, conservation measures, and pace of new connections in the London Area region and southwestern Ontario as a whole, to identify any impacts on completed or future bulk and regional plans and recommendations for the regions of interest.

On July 10, 2023, the Ministry of Energy released the Powering Ontario's Growth report, which outlines actions to support economic growth, decarbonization, and the ongoing transformation of Ontario's electricity system. As per that report, the Ontario government is planning for a more electrified Ontario, where economic growth continues to drive new jobs and emissions continue to be reduced. The South and Central Ontario bulk planning study being initiated this year will consider the objectives of the POG report across southwestern Ontario, as detailed in the IESO's 2024 Annual Planning Outlook.

Consideration of Potential Loads for the other planning regions of interest identified in the Central-West Plan will be integrated with POG objectives in the South and Central Ontario bulk planning study to better plan for potential linkages and their cumulative impact. Regional concerns identified in the Central-West Plan for Windsor-Essex and Kitchener-Waterloo/Cambridge/Guelph regions will inform ongoing or upcoming regional planning activities.

Appendix A: Application of Criteria

In developing this bulk plan, the IESO followed a number of steps including:

- Data gathering, including development of electricity demand forecasts
- Conducting technical studies to determine electricity needs and the timing of these needs
- Developing potential options
- Preparing a recommended plan including actions for the near and longer term

Throughout this process, engagement was carried out with stakeholders interested in the area, in the form of public webinars and targeted discussions with the affected communities, local distribution companies and transmitters.

This Plan documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The Plan helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

The overall objectives of planning are consistent among both regional and bulk planning, which are the following:

- Ensure reliability and service quality
- Enable economic efficiency
- Support sector policy and decision making

There are various reliability standards that, as the electricity system planner and operator, the IESO is obliged to meet. NERC and NPCC membership requires that the bulk system be planned to consider specific operating conditions, such as peak and light load, and a set of contingencies to ensure the bulk system is planned reliably and meets standards. Additionally, the IESO is required to demonstrate its adherence to these standards through compliance reporting.

Reliability standards require the IESO to define its own performance criteria that must be met under the conditions and contingencies specified. The Ontario Resource and Transmission Assessment Criteria (ORTAC) define the planning performance criteria for Ontario, which are more specific and/or more stringent standards than NERC/NPCC. The IESO also considers operational issues and solutions that simultaneously consider bulk system reliability needs, regional needs, and assets reaching end of life, as appropriate.

The study used the planning criteria in accordance with events and performance as detailed by: NERC TPL-001 "Transmission System Planning Performance Requirements" (TPL-001), NPCC Regional Reliability Reference Directory #1 "Design and Operation of the Bulk Power System" (Directory #1), and IESO ORTAC.

In addition to meeting established criteria and standards, the IESO also seeks to enable economic efficiency and support sector policy. Bulk system planning has a role in ensuring policy objectives can be incorporated with maximum benefit to ratepayers, and in identifying opportunities for improving overall system economics, especially in a competitive environment. This includes seeking economic opportunities, such as reducing losses, congestion, or other service costs, facilitating intertie/trade requirements, and providing timely and relevant information to market participants to enhance their participation and decision-making leading to greater market efficiency and competition. It also includes supporting policy implementation affecting the power grid, such as sensitivity analysis of the economic impact of carbon pricing policies on congestion costs, as well as considering community energy plans and goals.

Thermal Criteria

Table 10 shows the thermal criteria used for the Central-West studies. Post-contingency loadings up to the STE ratings is allowed only if the operator confirms they can manually resolve the thermal violations within 15 minutes. For a breaker-failure contingency, the operator can generally isolate the failed breaker and restore the unfaulty elements within an acceptable time and reduce the impact to single-element, post-contingency loadings up to the STE ratings are considered acceptable.

Note that the STE rating of a line should be recalculated for outage conditions if the pre-contingency loading of the line is larger than its continuous rating. The STE ratings that are normally provided were calculated for pre-contingency flows equal to the continuous ratings.

Table 10 | Thermal Criteria – Applicable Ratings

Condition	Pre-Contingency	Single-element Contingency	Common-tower Contingency	Breaker-failure Contingency
All In-service	Continuous	LTE	STE	STE
Outage	LTE	STE*	STE*	STE*

* STE rating must be recalculated for any element whose pre-contingency flow is larger than the continuous rating. The STE ratings that are normally provided were calculated for pre-contingency flows equal to the continuous ratings.

Voltage Criteria

Table 11 shows the voltage criteria based on ORTAC. Note that only main stations at 115 kV and higher voltage levels are monitored and tapped junctions and buses in the middle of circuits are not.

Table 11 | Voltage Criteria - ORTAC

Criterion	Nominal Voltage 500 kV	Nominal Voltage 230 kV	Nominal Voltage 115 kV
Maximum pre/post-contingency voltage	550 kV	250 kV	127 kV
Limited-time maximum post-contingency voltage*	575 kV	263 kV	133 kV

Criterion	Nominal Voltage 500 kV	Nominal Voltage 230 kV	Nominal Voltage 115 kV
Minimum pre-contingency voltage	490 kV	220 kV	113 kV
Minimum post-contingency voltage	470 kV	207 kV	108 kV
Maximum post-contingency absolute voltage deviation	10%	10%	10%

* Applicable only if voltages can be brought below their steady state post-contingency maximum limits within 30 minutes.

Arming RASs

With any one element out of service, arming an existing Remedial Action Scheme (RAS) is allowed only to account for local generation outages. Not more than a total 150 MW of load can be interrupted by configuration and load rejection.

With any two elements out of service, arming an existing Remedial Action Scheme (RAS) beyond 150 MW is allowed only to account for local generation outages. is allowed only to account for local generation outages. Not more than a total 600 MW of load can be interrupted by configuration and load rejection.

Note that locally-controlled voltage-based schemes such as Under Voltage Load Shedding (UVLS) and reactor/capacitor switching schemes are not RASs and can be used without restriction.

Respected Contingencies

Transfer capabilities, if reached, were derived based on single-element and common-tower contingencies. Breaker-failure contingencies were not be included in the initial transfer studies, but were evaluated with the transmission reinforcement option and resource scenarios in order to identify further needs. The rationale for not including breaker-failure contingencies in the initial transfer analysis is as follows:

- A breaker-failure contingency in a station usually removes two circuits on two different paths from that station. This should not be more limiting than the common-tower contingencies which removes two circuits on the same path.
- An operator can normally isolate the failed breaker and restore the unfaulty elements within an acceptable timeframe and reduce the contingency to a single-element.
- The contingency assessment used for the selected outages should identify voltage collapse scenarios encompass or exceed those resulting from a breaker-failure contingency.

Also, based on the study and based on the engineering judgment, contingencies in regions not relevant to the interfaces under study may be excluded.

Appendix B: Economic Assessment Assumptions

The following is a list of the assumptions made in the economic analysis:

- The net present value (NPV) of the cash flows is expressed in 2023 CAD.
- The USD/CAD exchange rate was assumed to be 0.77 for the study period.
- The NPV analysis was conducted using a four per cent real social discount rate.
- A long-term annual inflation rate of two per cent is assumed. A near-term (2023-2024) annual inflation rate of four per cent was assumed.
- The assessment was performed from an electricity consumer perspective and included all costs incurred by project developers, which were assumed to be passed on to consumers.
- The NPV study period for the options analysis term extended from the start of 2029, the year that the solution would need to be in-service, to the end of 2098, when a transmission asset replacement decision would be required.
- The life of the transmission line was assumed to be 70 years; and the life of the generation and storage assets was assumed to be 20 years. Cost of asset replacement were included where necessary to ensure the same NPV study period.
- Development timelines for transmission was assumed to be 3-6 years; development timelines for generation and storage were assumed to be 3-5 years following a procurement.
- Capital costs for the transmission options were determined based on $4.5 million to $8 million per kilometre estimates for a new double circuit 230 kV line, and a $175 million to $200 million per station estimate for new switching station costs. This was informed by the West of London Bulk Report analysis, Lakeshore switching station cost estimates in the Leave to Construct application evidence on file with the Ontario Energy Board, and input received from Hydro One.
- Both options will require voltage control devices, preferably in the form of small capacitors and reactors and/or automatic regulation in the form of a static var compensator sited with the new loads. Since this was common to all options, these costs were not factored into this analysis. The details of the voltage requirements will be specified in subsequent System Impact Assessments (SIA) for each project.
- Sensitivities to test the impacts of the how quickly Potential Load in the London Area materializes on the NPV were performed. Once the need in each sensitivity surpassed the capability of the transmission solutions being evaluated, the demand was flat lined for the purposes of the production cost analysis. While NPVs were calculated based on the life of the longest asset (70 years), holding the need at 300 MW (the incremental capability achieved through the transmission reinforcement) ensures an equal comparison of options.

- The combination of wind and storage resources was identified as one of the lowest-cost, non-emitting resource alternatives that could potentially be built in time to meet the need identified. The estimated levelized cost of capital and fixed operating costs assumed is about $150,000-160,000/MW (2023 CAD) for wind and $210,000-270,000/MW (2023 CAD) for storage for sensitivity A, and $350,000-380,000/MW (2023 CAD) for wind and $210,000-270,000/MW (2023 CAD) for storage for sensitivity B. Costs are based on the 2023 National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB) Workbook publication, and accounts for the impact of the Clean Investment Tax Credit. Total energy storage system costs are composed of capacity and energy costs (i.e. energy storage devices are constrained by their energy reservoir), for a six-hour storage resource. Cost ranges were developed by using different wind production profiles.
- Sizing of the storage solution was based on meeting the peak capacity and peak energy requirements for the local reliability need, such that the reservoir size is capable of using existing gas resources to sufficiently charge to meet the hours of unserved energy.
- Sizing of the storage option for the purposes of this analysis was conducted assuming perfect foresight, i.e. demand is predictable and so the facility knows exactly when and how much energy is needed and charges ahead of time, sometimes requiring multiple days to charge, in order to supply that need.
- Resources were assumed to be sited at the preferred location, at the Firm Load tap point or between the tap and Firm Load supply station, up to the capability of the existing system.
- The magnitude of demand growth in this area exceeds the capability of energy efficiency or demand response to cost-effectively reduce the needs, and were therefore not considered as alternatives, but is considered further through ongoing regional planning in the area.
- System capacity value was $159,000/MW-year (2023 CAD) based on an estimate for the cost of a portfolio of non-emitting resources. A low sensitivity was assessed with a system capacity value of $37,000/MW-year (2023 CAD), reflecting the winter 2024/2025 Capacity Auction Clearing Price.
- The cost of constraining the generation alternative to produce energy for a local need versus the cost of system supply was considered.
- A resource's potential contribution to system needs, outside of serving the local needs, was assessed based on the deliverability of that resource's remaining capacity to province's load centre.

Appendix C: Connection Configuration Requirement

Based on the location of the Firm Load, up to 180 MW can be connected to Buchanan TS via the existing 230 kV tap lines between Buchanan TS and Edgeware TS, consistent with Hydro One's proposed connection to the customer. The remaining 440 MW of Firm Load must be connected to the electricity system from the Buchanan to Middleport 230 kV circuits, consistent with Hydro One's proposed connection arrangement to the customer. To maintain redundant supply, the Firm Load must have dual supply (i.e., be supplied via two of the three Buchanan to Middleport 230 kV circuits: M31W, M32W and M33W). However, there are differences in transfer capability and load security between the three 230 kV circuits along the Buchanan to Middleport path.

M32W supplies both Ingersoll TS and Brantford TS, while M31W only supplies Ingersoll TS and M33W supplies Brantford TS (the smaller of the two stations). Thus, the option to connect the Firm Load to M31W and M32W was not considered because the circuits are already heavier loaded.

Two connection options were considered: M31W+M33W, and M32W+M33W.

Based on the results shown in this section, the recommended connection for the Firm Load is M31W+M33W.

M31W+M33W Connection Assessment

Studies indicate that there are post-contingency thermal constraints for the M31W+M33W connection after 600 MW of Firm Load is added, under high generation assumptions. There are also low voltage concerns in the London Area region after 900 MW of load is added (620 MW of Firm Load and 380 MW of Potential Load in the London Area). There are no load security constraints identified.

Thermal and Voltage Assessment

The thermal rating for M31W is lower than the other two circuits, as shown in **Table 12**.

Table 12 | Current Summer Thermal Ratings for the MxW Circuits (Buchanan TS to Salford JCT)

Circuit	Continuous Rating (93˚C) A	Continuous Rating (93˚C) MVA	LTE Rating (127˚C) A	LTE Rating (127˚C) MVA
M31W	1,100	440	1,500	580
M32W	1,400	550	1,800	730
M33W	1,400	550	1,800	730

Under the base generation assumptions, there are no pre- or post-contingency thermal concerns identified to supply the Firm Load – 620 MW of load transfer can be achieved before reaching a thermal limitation. However, beyond 800 MW (620 MW of Firm Load + 180 MW of additional load in the London Area region), post-contingency thermal constraints are seen following the loss of M32W+M33W. An upgrade to the M31W circuit would be needed to enable further load in the London Area, with the base generation.

Under the high generation assumptions and no imports, post-contingency thermal limitations on M31W are seen when the Firm Load is 600 MW, for the loss of M32W+M33W.

The next constraint for both the summer base and high generation cases is seen when approximately 900 MW of load is added, when the load flow case does not solve for contingencies that result in the loss of MxW circuits. This occurs immediately after the low voltage concerns, and indicates that there are voltage collapse concerns at Ingersoll TS due to the sheer amount of load being added.

Similar but less restrictive results are seen for the winter cases, due to the higher winter thermal ratings.

The results of the thermal and voltage assessment are summarized in **Table 13**.

Table 13 | Supply Capability with M31W+M33W Firm Load Connection

Generation Scenario	Element(s) out of Service	Additional Supply Capability (MW)	Limitation	Limiting Contingency	Limiting Element
Base	None	800	Thermal	M32W+M33W	M31W Buchanan TS to Firm Load tap
High	None	600	Thermal	M32W+M33W	M31W Buchanan TS to Firm Load tap
Base/High	None	900	Low Voltage	M31W+M33W, M32W+Q25BM	Ingersoll TS
Base/High	None	900	Voltage Collapse	M32W, M31W M32W+M33W, M31W+Q23BM, M32W+Q25BM	Ingersoll TS
Base/High	M32W	900	Low Voltage	Pre-contingency	Ingersoll TS

Load Security Assessment

Considering load security criteria, an N-1-1 (loss of M31W and M33W) would result in the Firm Load connected to the MxWs being lost (430 MW; 620 MW less the 190 MW load connected to the tap to Buchanan TS), which is within the 600 MW limit for load security in ORTAC.

No voltage violations were identified.

M32W +M33W Connection Assessment

Studies indicate that there are post-contingency thermal constraints on M32W for the loss of M33W with M31W out of service, after approximately 940 MW of load (620 MW of Firm Load and 320 MW of Potential Load). There are also low voltage concerns in the London Area region after approximately 900 MW of load is added (620 MW of Firm Load and 380 MW of Potential Load in the London Area region). Load security constraints are identified beyond 620 MW of Firm Load.

Thermal and Voltage Assessment

Under the base generation assumptions, there are no pre- or post-contingency thermal concerns identified to supply the Firm Load – 620 MW of load transfer can be achieved before reaching a thermal limitation. However, beyond ~940 MW (620 MW of Firm Load and 320 MW of Potential Load), post-contingency thermal constraints are seen following the loss of M33W with M31W out of service. Since this occurs under outage conditions, a RAS is permissible under ORTAC criteria, so no upgrades are required.

Under the high generation assumptions and no imports, there are no thermal concerns identified to supply the Firm Load – 620 MW of load transfer can be achieved before reaching a thermal limitation. However, beyond ~750 MW (620 MW of Firm Load and 130 MW of Potential Load), post-contingency thermal constraints are seen for the N-1-1 (i.e., following the loss of M33W with M31W out of service). Since this occurs under outage conditions, a RAS is permissible under ORTAC criteria, so no upgrades are required.

The next constraint for both the summer base and high generation cases is seen when approximately 980 MW of load is added, resulting in the load flow case not solving for the loss of M32W+M33W, M31W+Q23BM, and M32W+Q25BM. This indicates that there are voltage collapse concerns at Ingersoll TS due to the sheer amount of load being added.

Similar, but less restrictive, results are seen for the winter cases, due to the higher winter thermal ratings.

The results of the thermal and voltage assessment are summarized in **Table 14**.

Table 14 | Supply Capability with M32W+M33W Firm Load Connection, Summer

Generation Scenario	Element(s) out of Service	Additional Supply Capability (MW)	Limitation	Limiting Contingency	Limiting Element
Base	M31W	940	Thermal	M33W	M32W Buchanan TS to Firm Load tap
High	M31W	750	Thermal	M33W	M32W Buchanan TS to Firm Load tap
Base/High	None	980	Voltage Collapse	M31W*	Ingersoll

*Also seen for other configurations that remove one MxW circuits.

Load Security Assessment

Considering load security criteria, an N-2 or N-1-1 (loss of M32W and M33W) would result in the Firm Load connected to the MxWs being lost (430 MW; 620 MW less the 190 MW load connected to the tap to Buchanan TS) plus the load at Brantford TS (140-170 MW between 2030 and 2043), which would violate the 600 MW limit for load security in ORTAC.

Comparison of Connection Options

The amount of additional load (Firm Load and/or Potential Load) that can be supplied in the London Area region is outlined in **Table 15** for both connection options, based on the most restrictive case (summer high generation). The M31W circuit has the lowest transfer capability of the three, primarily due to the smaller clearances and span lengths required to accommodate the surrounding farmlands and farm equipment. Thus, from a thermal perspective, more load can be enabled through the M32W+M33W connection.

Table 15 | Additional Supply Capability for the Firm Load Connection Options

System State	All In-Service Additional Supply Capability (MW)	All In-Service Limitation	Outage Supply Capability (MW)	Outage Limitation
Current System, load connected to M31W and M33W	600	Thermal	600*	Thermal
Current System, with load connected to M32W and M33W **	980	Voltage	750*	Thermal

* Assumed to be equal to all in-service limit, as the end state for the n-1-1 is the same as the n-2 condition.

** Based on the 2030 forecast, M32W+M33W contingency without any Firm Load removes Brantford TS.

However, the M32W+M33W connection configuration violates the load security criteria, for which operational measures are not available. Hence, it is recommended that the Firm Load connect to M31W+M33W.