BY EMAIL AND RESS

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August 25, 2026

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

Dear Mr. Murray,

EB-2026-0018 – Hydro One Networks Inc. Leave to Construct Application – Orleans Area Reinforcement Project – Interrogatory Responses

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

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

- **Exhibit I, Tab 1, Schedule 6, part d** – pertaining to requests seeking information regarding the calculation of the Project's line losses analysis;

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

In accordance with subsection 6.1.2, 6.1.4 and 6.1.7 of the Practice Direction and subsections 10.01 and 10.02 of the Rules, Hydro One has proposed that the confidential versions of its responses to OEB Staff interrogatory 6(d) only be made available to a party that has signed a Declaration and Undertaking. With respect to the foregoing requests, by way of separate filing, Hydro One's counsel will be filing a motion consistent with the Rules and the Practice Direction.

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

Sincerely,

Pasquale Catalano

OEB STAFF INTERROGATORY - 01

Reference:
Exhibit B-1-1, Page 3

Preamble:
According to Reference 1, Hydro One Networks filed the final Environmental Study Report (ESR) on April 2, 2026. A hyperlink to the ESR is provided in the application; however, the link is broken and does not open the ESR for the Orleans Area Reinforcement Project (Project).

Interrogatory:
a) Please provide the final ESR for the Project.

Response:
a) As requested, please refer to the link below for a copy of the final ESR for the Project: https://www.hydroone.com/abouthydroone/CorporateInformation/majorprojects/Orleans/Documents/Final-ESR-Orleans-Area-Reinforcement.pdf

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OEB STAFF INTERROGATORY - 02

Reference:
1. Exhibit B-7-1, Page 1
2. Exhibit H-1-1, Attachment 1, Page 79
3. https://www.hydroone.com/about/indigenous-partnerships

Preamble:
According to Reference 1, the estimated capital cost of the Project is $99.9 million.

According to Reference 2, regular outreach was made to three First Nations during the development of the Integrated Regional Resource Plan (IRRP).

According to Reference 3, Hydro One Networks collaborates on all large-scale transmission line projects valued at more than $100 million through its 50-50 First Nation Equity Partnership Model.

Interrogatory:
a) Please confirm whether or not Hydro One Networks is seeking to apply its 50-50 First Nation Equity Partnership Model to the Project.

b) Does the $100 million threshold for Hydro One Networks' 50-50 First Nation Equity Partnership Model apply to the total capital cost of projects that are predominantly transmission line projects or does it apply specifically to the transmission line component of any given project?

c) If the final capital costs of the Project were to exceed $100 million, would the Project qualify for Hydro One Networks' 50-50 First Nation Equity Partnership Model?

Response:
a) No, the Project does not qualify for Hydro One's 50-50 First Nation Equity Partnership Model.

b) The $100 million threshold associated with Hydro One's 50-50 First Nation Equity Partnership Model applies solely to the transmission line component of a project. Please refer to https://www.hydroone.com/about/indigenous-partnerships#building-as-partners for further reference.

c) Please refer to the responses in part a) and part b) above.

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OEB STAFF INTERROGATORY - 03

Reference:

1. Exhibit B-2-1, Page 2
2. 2015 Ottawa Area IRRP

Preamble:

According to Reference 1, the existing H9A circuit is designed and rated for 230 kV but is currently operated at 115 kV.

According to Reference 2, Orleans Transformer Station (TS) was placed in-service in 2015 with an initial dual supply (230 kV and 115 kV) configuration.

Interrogatory:

a) Why was the Hawthorne to Orleans section of the H9A circuit built to 230 kV standards but operated at 115 kV? When was the line placed in-service at its current rating?

b) Why was Orleans TS designed with an initial configuration of one 115 kV supply and one 230 kV supply? Were there already plans to upgrade it to a 230 kV Dual Element Spot Network (DESN) design when the station was first conceived?

c) What is the age of the 115 kV equipment at Orleans TS that will be removed? Please provide any plans for some of this equipment to be redeployed at other sites in the province in the future.

Response:

a) As part of the Hydro One – Hydro Quebec 1250MW interconnection project, which was approved by the OEB under section 92 of the OEB Act in proceeding RP-2000-0068, the existing transmission facilities (circuits H9A and D5A) were rebuilt to accommodate construction of the new 230 kV interconnection line (circuits A41T and A42T) between Hydro One's Hawthorne TS and Hydro Quebec's Outaouais TS within the existing corridor.[1]

Prior to this interconnection project, circuits D5A and H9A were each located on separate single-circuit tower lines within the existing corridor. As part of the interconnection project, these two single-circuit tower lines were rebuilt into two new 230 kV double-circuit tower lines, with one 230 kV double-circuit tower line for the new

[1] RP-2000-0068, Exhibit B, Tab 2, Schedule 1, pp.2-3.

interconnection circuits and the other 230 kV double-circuit tower line for circuits D5A and H9A.

As a result, circuit H9A between Hawthorne TS to Orleans TS is a 230 kV ready circuit; however, it has continued to be operated at 115 kV.

The Hydro One – Hydro Quebec interconnection began commercial operation in 2009, while the rebuilt 230 kV double-circuit tower line for circuits D5A and H9A has been in-service since 2008.

b) The current configuration of Orleans TS reflects the transmission supply facilities that were available in the area at the time the station was planned and constructed. At that time, there was only one 230kV transmission line (circuit D5A) that was available; accordingly, circuit H9A was used to provide a second supply to the station.

Orleans TS was planned and designed with consideration for a future standard 230 kV DESN configuration should regional system needs necessitate the addition of a second 230 kV supply. As such, where possible, the station was designed and constructed to facilitate the conversion of its second supply to 230 kV operation.

c) Orleans TS was placed in-service in 2015, therefore the 115 kV equipment (i.e., transformer and related equipment) planned to be replaced as part of the Project has been in use for 11 years. This 115 kV equipment will be maintained at Hydro One’s Central Maintenance Services site for use as spares on the system.

OEB STAFF INTERROGATORY - 04

Reference:

1. Exhibit B-3-1, Attachment 1, Pages 3-5
2. Exhibit H-1-1, Attachment 1, Page 26
3. Exhibit H-1-1, Attachment 2, Pages 61-63
4. 2015 Ottawa Area IRRP
5. 2015 Ottawa Area IRRP – Appendix, Page 16
6. 2020 Ottawa Sub-Region IRRP, Pages 66-71
7. 2020 Ottawa Sub-Region IRRP Appendices, Appendix B, Pages 19-20
8. Exhibit H-1-1, Attachment 2, Pages 68-75

Preamble:

According to Reference 1, the need and rationale for the Project are outlined in the 2023 Orleans Area Planning Study, which re-evaluated the conclusions of the 2020 Ottawa Area IRRP under updated demand growth forecasts for the City of Ottawa. The 2023 Orleans Area Planning Study was not included in the application and is not available on the Independent Electricity System Operator (IESO) public website.

Interrogatory:

a) Please provide the 2015 Ottawa Area IRRP, including appendices.

b) Please provide the 2020 Ottawa Area IRRP, including appendices, mentioned in Reference 1.

c) Please provide the 2023 Orleans Area Planning Study mentioned in Reference 1.

d) What is the need that the Project addresses?

e) Please provide the evaluation of the wires and non-wires alternatives to the Project.

f) What were the underlying factors that led to the increase in forecast demand for the Orleans Area between the 2020 IRRP and the 2023 Orleans Area Planning Study?

g) Table 1 below represents an attempt to summarize the different electricity demand forecasts for the Orleans Area for the year 2032 that informed recent regional planning exercises. Please confirm whether or not the figures in Table 1 are an accurate representation of the forecasts used for their respective regional planning reports. If there are any inaccuracies, please provide the correct figures.

Table 1 - 2032 Forecast Demand for the Orleans Area

	2032 Forecast Demand for the Orleans Area [MW]			
Source	Bilberry Creek TS	Orleans TS	Mer Bleue MTS	Total
2015 IRRP (Reference 5)	55	109	-	164
2020 IRRP (Reference 7)	50.8	131.3	-	182.1
2023 Orleans Area Planning Study	(Not publicly available.)			
2025 IRRP (Reference 2)	(Not publicly available.)			
2026 RIP Summer – Ref (Reference 8)	0.0	149.8	68.2	218.0
2026 RIP Winter – Ref (Reference 8)	0.0	96.1	95.8	191.9
2026 RIP Summer – High (Reference 8)	0.0	151.2	74.5	225.7
2026 RIP Winter – High (Reference 8)	0.0	97.6	117.5	215.1

h) Please provide the 2032 forecast demand, in MW, for the Orleans area that informed the 2023 Orleans Area Planning Study and the 2025 IRRP, broken down by supply station.

i) Please provide the actual annual peak demand, in MW, for the Orleans area for the years 2020 to 2025, broken down by supply station.

j) According to Reference 8, Mer Bleue MTS is forecasted to be winter-peaking while Orleans TS is forecasted to remain summer-peaking. Why is there a discrepancy between the two stations when they are supplying load in the same area?

k) According to Reference 8, Orleans TS has a summer limited time rating (LTR) of 118.2 MW. According to Reference 6, converting Orleans TS to a dual 230 kV supply would expand its capacity to 153 MW. According to Reference 8, the 2044 forecast summer demand for Orleans TS is 173.2 MW in the reference load scenario and 174.2 MW in the high load scenario. Please explain how Orleans TS is expected to supply load that exceeds its capacity.

l) According to Reference 8, the 2044 forecast winter demand for Mer Bleue MTS is 147.8 MW in the reference load scenario and 175.9 MW in the high load scenario. Its winter LTR, however, is only 123.5 MW. Please explain how Mer Bleue MTS is expected to supply load that exceeds its capacity.

Response:

a) As requested, please refer to the links below for a copy of the IESO's 2015 Ottawa Area IRRP, including appendices:
   - https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Greater-Ottawa/2015-Ottawa-IRRP-Report.pdf
   - https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/greaterottawa/Documents/2015-Ottawa-IRRP-Appendix.pdf

b) As requested, please refer to the links below for a copy of the IESO's 2020 Ottawa Area IRRP, including appendices:
   - https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ottawa/Ottawa-Sub-Region-IRRP-20200304.pdf
   - https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ottawa/Ottawa-Sub-Region-IRRP-Appendices.pdf

c) As requested, please refer to Attachment 1 of this Schedule for a copy of the IESO's 2023 Orleans Area Planning Study.

d) The needs addressed by the Project are described throughout the Application and supporting evidence. Please refer to **Exhibit B, Tab 3, Schedule 1** and corresponding attachment; **Exhibit B, Tab 6, Schedule 1**; and the recent regional planning documentation provided in **Exhibit H, Tab 1, Schedule 1, Attachments 1 and 2**.

e) Wires and non-wires alternatives are considered through the regional planning process and, where appropriate, are evaluated and documented in the IESO's IRRP. For the proposed Project, there were no effective non-wire solutions identified to defer or eliminate this system need. As a result, no further analysis was conducted. Please refer to **Attachment 1 of Exhibit H, Tab 1, Schedule 1** for the 2025 IRRP Report, and the corresponding 2025 IRRP Appendices for further details in this matter. Additionally, the IESO's 2023 Orleans Area Planning report, referenced in response to part c) above, also indicates that non-wire alternatives would not be able to address the need completely.

f) As described in **Attachment 1 of Exhibit B, Tab 3, Schedule 1**, significant demand growth has occurred across the City of Ottawa, driven by long-term development and electrification trends, which has resulted in the recommendation for the Orleans area to be re-evaluated. This is also further discussed in the IESO's 2023 Orleans Area Planning Study provided in response to part c) above.

g) Hydro One is unable to validate the various electricity demand forecasts for the Orleans Area presented in the IESO's IRRP reports and summarized in Table 1 above. Hydro One notes, however, that over the last 10 years, demand forecast has significantly changed in this region. The load forecasts shown in the 2026 RIP report, provided in **Attachment 2 of Exhibit H, Tab 1, Schedule 1**, represent the most current forecast information available from the LDCs and IESO.

h) The forecast information that informed the Orleans area assessment is included in the 2023 Orleans Area Planning Study, which is provided as Attachment 1 to this Schedule.

i) The actual station demand, non-weather adjusted, in MW, for the Orleans area over the period of 2020 to 2025, is provided in table below.

	2020	**2021**	**2022**	**2023**	**2024**	**2025**
Name of Station	Summer	Summer	Summer	Summer	Summer	Summer
Bilberry Creek TS	50.7	52.6	47.6	47.5	37.1	54.8
Orleans TS	90.6	95.4	83.4	94.3	106.9	101.9

j) Orleans TS currently supplies multiple LDCs, while the future Mer Bleue MTS will only supply one LDC. Different LDCs have different forecasting methodologies and assumptions for winter and summer load demands. For example, one LDC may be forecasting significant increases in demand because of electrification (i.e., electric heat and EVs) relative to another LDC. These differences can result in different winter- and summer-peaking forecasts.

k) Regional planning is a continuous process and future long-term transformation and supply capacity requirements are monitored and assessed on an on-going basis to ensure a reliable supply of electricity to the region. Should forecast demand for Orleans TS continue to trend upward as suggested, additional transmission needs and recommendations for the region will be reflected in future regional planning reports.

l) Hydro One cannot comment on Hydro Ottawa's plans for Mer Bleue MTS if/when the station reaches its capacity. As noted in the response to part k) above, regional planning is a continuous process and future long-term needs are monitored and assessed on an on-going basis to ensure a reliable supply of electricity to the region.

Orleans Area Planning Study

Greater Ottawa Region Working Group Report (Internal)
May 17, 2023

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Disclaimer

This document and the information contained herein is provided for informational purposes only. The IESO has prepared this document based on information currently available to the IESO and reasonable assumptions associated therewith, including relating to electricity supply and demand. The information, statements and conclusions contained in this report are subject to risks, uncertainties and other factors that could cause actual results or circumstances to differ materially from the information, statements and assumptions contained herein. The IESO provides no guarantee, representation, or warranty, express or implied, with respect to any statement or information contained herein and disclaims any liability in connection therewith. Readers are cautioned not to place undue reliance on forward-looking information contained in this report as actual results could differ materially from the plans, expectations, estimates, intentions and statements expressed in this report. The IESO undertakes no obligation to revise or update any information contained in this report as a result of new information, future events or otherwise. In the event there is any conflict or inconsistency between this document and the IESO market rules, any IESO contract, any legislation or regulation, or any request for proposals or other procurement document, the terms in the market rules, or the subject contract, legislation, regulation, or procurement document, as applicable, govern.

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List of Abbreviations

DESN	Dual Element Spot Network
DG	Distributed Generator
DS	Distribution Station
EE	Energy Efficiency
EOL	End of Life
FIDS	Flow Into Dobbin and Sidney
FIO	Flow Into Ottawa
GS	Generating Station
HOL	Hydro Ottawa Limited
HVDC	High Voltage Direct Current
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
MTS	Municipal Transformer Station
MVA	Mega Volt Ampere
MW	Megawatt
NERC	North American Electric Reliability Council
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource Transmission Assessment Criteria
SS	Switching Station
TS	Transformer Station
ULTC	Under Load Tap Changer

1. Executive Summary

The Orleans Area Planning Study was carried out by the Technical Working Group between the end of the 2020 Greater Ottawa IRRP study and the current 2024 IRRP study. It examines forecast capacity, reliability, and end-of-life needs expected to arise over the next 20 years. The Orleans area is served by two stations, Bilberry Creek TS and Orleans TS, and supplied by the Ottawa 115 kV system from Hawthorne. The issues examined through this study include:

- Bilberry Creek TS end-of-life need
- Orleans Area reliability needs
- Ottawa 115 kV system capacity needs

To mitigate forecast risk associated with high growth scenarios (i.e. electrification), preserve options to increase station supply capability in the future, maintain existing level of reliability to existing customers, defer the need for additional upgrades to the Ottawa 115 kV system beyond the third auto-transformer at Merivale TS[1], and maintain the existing import capability from hydro-electric generation from Lièvre Power LP onto 115 kV circuit H9A, the following integrated solution package is recommended to address the transmission asset renewal needs at Bilberry Creek and capacity needs at Orleans TS over the long-term:

- Decommission Bilberry Creek TS
- Upgrade D5A/H9A transmission line to carry an additional 230 kV circuit from Hawthorne TS to Orleans TS
- Upgrade Orleans TS to accommodate two 230 kV supply circuits
- New 230 kV supply station in Orleans
- Pursue up to 25 MW of additional system cost-effective energy efficiency in the Ottawa 115 kV system area over the 20 year planning horizon

This solution package is estimated to cost approximately $75 M. The included reinforcements ensure reliability in the Orleans area is sufficient for the next 20 years, and provides an additional 65 MW of additional capacity beyond the demand forecast for future growth.

[1] Transferring load from the 115 kV to the 230 kV system will inherently defer the forecast capacity needs on the 115 kV system based on the Orleans Area Planning Study demand forecast. The benefits (timing and value) will be confirmed as part of the current Ottawa Area Sub-region IRRP.

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. 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 transmission 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 which 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. Also covered are regulatory compliance studies and reporting requirements, such as those required by the North American Electric Reliability Corporation (NERC) reliability standards and the Northeast Power Coordinating Council (NPCC) criteria.

2.2 Regional Planning for Greater Ottawa

The most recent cycle of regional planning for Greater Ottawa (completed in 2020) identified a station capacity need at Orleans TS and an asset renewal need at Bilberry Creek TS including the transformers and low voltage circuit breakers. A recommendation was made to address the two needs which included the refurbishment of Bilberry Creek TS and building two additional distribution feeders out of the station to support load growth within Hydro Ottawa Limited's (HOL) distribution system. However, since the 2020 IRRP, there have been significant developments in demand growth throughout the city of Ottawa, and the Greater Ottawa Region Technical Working Group (TWG) decided to revisit the recommendation.

The re-evaluation of the Orleans' Area recommendations is being carried out between cycles of regional planning for Greater Ottawa. The report documents the technical working group's analysis and the conclusions reached and is intended for the transmitters and distributors in the technical working group, enabling them to proceed with long lead time activities that are required now (connection assessments, design engineering, estimating, approvals). The formal public recommendations will be communicated in current Ottawa Area Sub-region IRRP cycle which recently commenced in March 2023 and expected to be completed in September 2024.

2.3 Ottawa Transmission Supply Overview

Ottawa is a major load center in eastern Ontario which is primarily supplied by:

- two 500 kV circuits from Lennox TS in Lennox and Addington County

- two 230 kV circuits from St. Lawrence TS in Cornwall
- one 230 kV circuit Chats Falls SS
- one 115 kV circuit from Barrett Chute GS
- one 115 kV circuit from Stewartville GS
- an inter-connection with Quebec's transmission system at Hawthorne TS located in the east side of Ottawa

Ottawa historically peaks in summer at slightly over 1800 MW and is forecasted to grow to approximately 2700 MW over the next 20 years. There is very little internal generation in Ottawa, with only one transmission connected generator being a 70 MW combined cycle gas plant. There are a number of distribution connected generators located within Ottawa, most notably being the Chaudière Falls hydro-electric plants which combine to approximately 90 MW.

The transmission system supplying Ottawa has a number of interfaces that can limit the ability to serve load in Ottawa and facilitate power transfers from generation and imports located in eastern Ontario for use efficiently and effectively across the Ontario grid. These interfaces are shown in Error! Reference source not found.. The loads in Ottawa are primarily supplied by a number of 230 and 115 kV transmission circuits that emanate from the two stations Merivale TS and Hawthorne TS which act as central electricity hubs for the city.

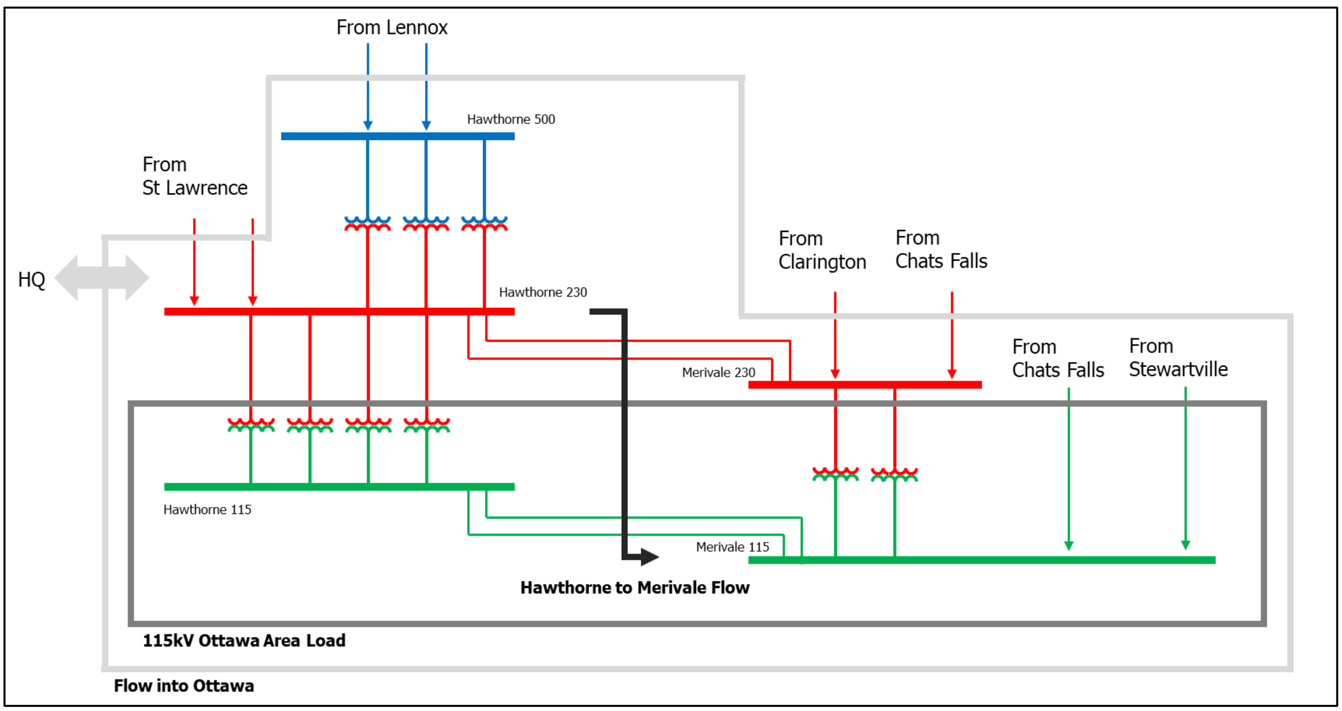

Figure 1. Ottawa Area Interfaces

Flow into Ottawa

The "Flow into Ottawa" (FIO) interface is bounded by 500 kV circuits X522A and X523A from Lennox TS, and 230 kV circuits C3S from Chats Falls GS, E34M from Almonte TS, L24A and B5D from St. Lawrence TS. The FIO transfer limit is constrained by post contingency thermal limitations and voltage instability. The FIO transfer limit acts as an upper bound for the maximum amount of load that can be served across the whole Greater Ottawa region, which includes the United Counties of Prescott Russell, and the United Counties of Stormont, Dundas and Glengarry.

Forecasted load growth in the Greater Ottawa region is expected to exceed the FIO transfer limit within the next 10 years. This interface was studied as part of the Gatineau Corridor EOL bulk system planning study which was completed and published in December 2022, and made recommendations to accommodate Ottawa's forecasted demand up to the mid-2030s.

115 kV Ottawa Area Load

The 115 kV Ottawa Area Load totals approximately 1200 MW and represents nearly 60% of the Greater Ottawa Region demand. This load is served primarily through six (6) 230-115 kV auto-transformers, four (4) of which are located at Hawthorne TS and two (2) at Merivale TS. The load meeting capability of the Ottawa 115 kV System is currently constrained by pre-contingency and post-contingency thermal violations. Downstream transmission limitations of 115 kV transmission lines emanating from Hawthorne TS and Merivale TS, and the 115 kV connected supply stations were studied through previous cycles of regional planning, and will be reviewed again in the current cycle of Ottawa Area Sub-region IRRP.

Hawthorne to Merivale Flow

The Hawthorne to Merivale path is comprised of 230 kV circuits M30A, M31A, and 115 kV circuits A8M and A3RM between Hawthorne TS and Merivale TS. This path allows for transfer of power westwards across Ottawa to facilitate economic energy transfers through our interties, dispatch of generation in eastern Ontario and to serve loads in west Ottawa on both the 230 kV and 115 kV system. The flow across the Hawthorne to Merivale path is constrained by post contingency thermal violations today, and there is an ongoing plan to upgrade the M30A/M31A circuits, addressing the current limiting phenomena.[2]

Orleans Area Electricity System Overview

Orleans is a suburb in the eastern part of the City of Ottawa located along the Ottawa River. Like other areas outside the Greenbelt[3], development is underway in this area, including development of the East Urban Community and the Orleans Industrial Park. The area is supplied by one 230 kV circuit (D5A) and a number of 115 kV circuits (including H9A, A2, and A4K) that emanate from Hawthorne TS toward the northeast. The Orleans area is supplied by Bilberry Creek TS which is supplied by the 115 kV system, and Orleans TS is supplied by both the 230 kV and 115 kV systems. This study will focus on needs in the Orleans planning region, as defined by the five stations and two circuit systems listed above. Figure 2 below shows the electricity system in the Orleans region.

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[2] More information about the Hawthorne to Merivale Reconductoring Project is available on the Ontario Energy Board website (link)

[3] More information about the Greenbelt is available on the National Capital Commission website (link)

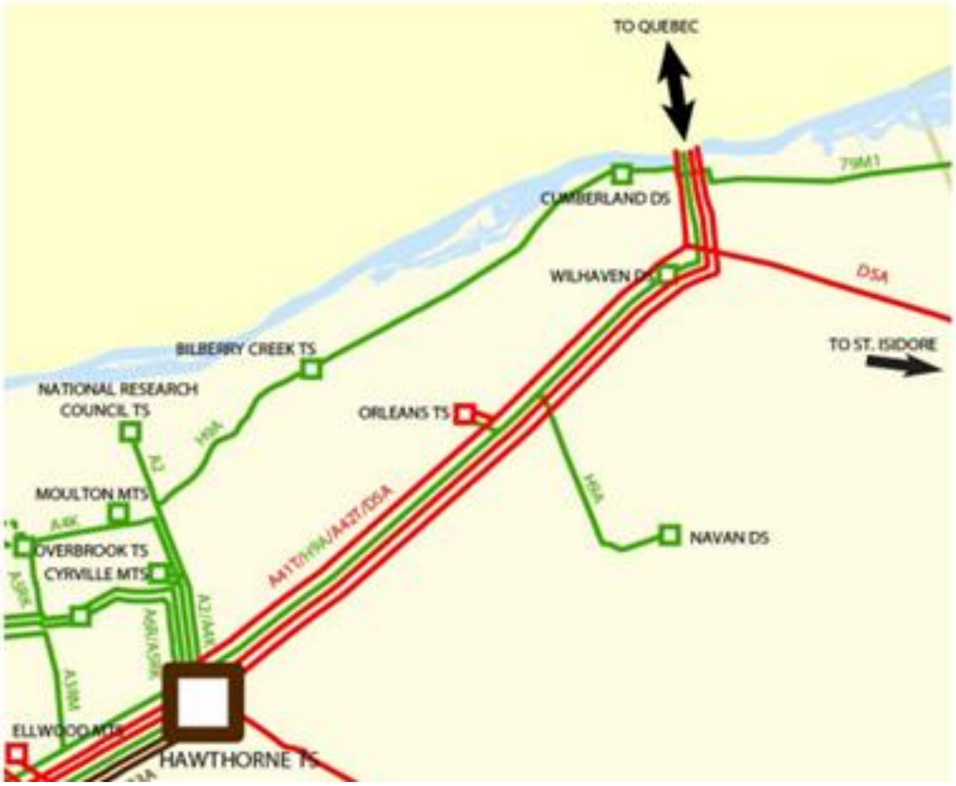

Figure 2. Eastern Ottawa Transmission System

3. Demand Forecasts

Although this study focuses on more local needs in the Orleans area, a demand forecast for the entire Greater Ottawa Region was developed for this study in 2022 to aid in identifying interdependencies between the needs in the Orleans area and the upstream Ottawa 115 kV system. The development of the demand forecast started with compiling a 20-year "gross" forecast, representing the total amount of electricity being used by end-use customers. Afterwards, a "planning" forecast (formerly known as a "net" demand forecast) was created, representing the electricity demand as seen by the transmission system. Local electricity demand can be met through Energy Efficiency (EE) initiatives, which help reduce the amount of electricity being consumed by end-use customers. It may also be met through Distributed Generation (DG) which are located within the distribution system offsetting the total amount of electricity needed from the transmission system. In planning the transmission system, a planning demand forecast, which takes into consideration the impacts of DG and EE, is used to more accurately represent how much demand the transmission system must be able to handle.

Another important consideration when generating forecasts is the correlation between electricity demand and weather. In Southern Ontario, indoor heating is provided primarily through gas furnaces, and thus little electricity is used in heating houses and businesses during the winter months. However, indoor cooling is provided primarily through electric air conditioners, which use more electricity than almost any other household appliance. As such, it is generally found that the higher the temperature, the higher the electricity demand.[4] A linear correlation can be found between temperature and electricity demand. The demand forecast is adjusted for both normal and extreme weather conditions based on historical data. Normal weather represents the highest annual temperature observed one in two years. Extreme weather represents the highest annual temperature observed one in 10 years.

As the load forecast is prepared at a station level, one additional consideration is the coincidence of when each individual station would peak. When assessing and determining broader transmission needs such as the thermal capacity of a transmission line serving multiple stations, or the voltage performance of a general area, a regional coincident station peak forecast is used. However, when examining the supply capacity of an individual supply station, a regional non-coincident station peak forecast is used.

3.1 Greater Ottawa Region Demand Forecast

A 20-year planning forecast was developed for the Greater Ottawa Region and is illustrated in Error! Reference source not found.. The forecast shown represents the coincident peak demand of the entire region. The forecast shows an average demand growth of 1.7% per year and a total increase of 750 MW over the next twenty years.

[4] This assumption may change going forward due to greater decarbonization/electrification and that this will be examined in the current IRRP.

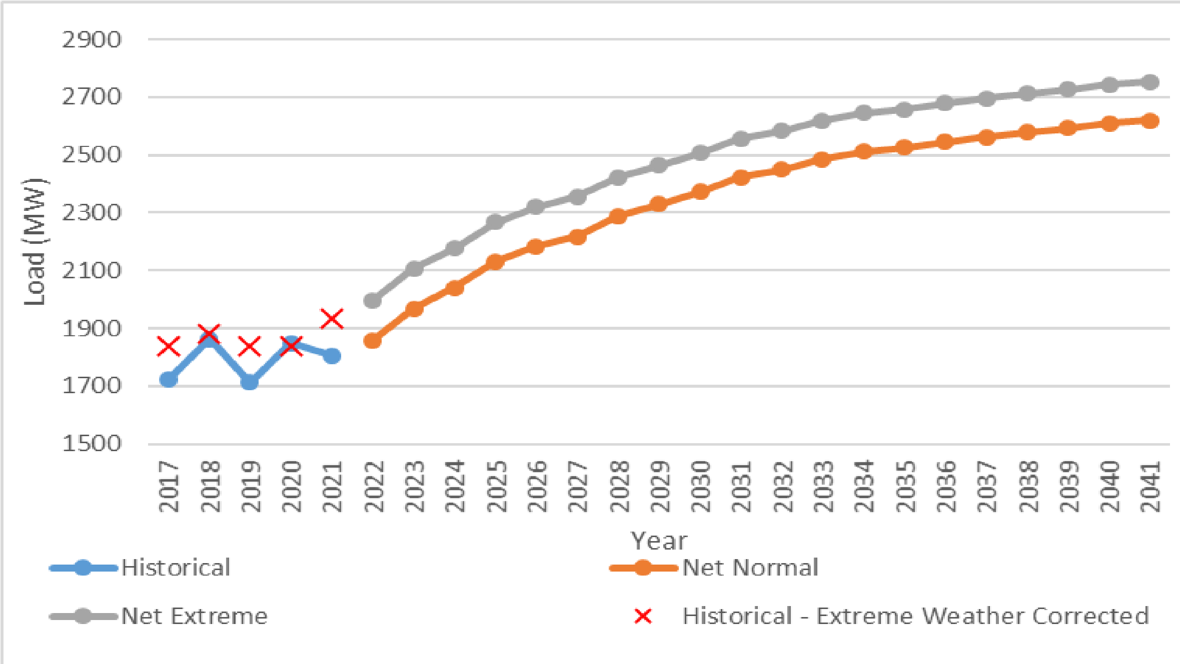

Figure 3. Greater Ottawa Planning Forecast

3.2 Ottawa 115 kV System Demand Forecast

As a subset of the Greater Ottawa Region, the Ottawa 115 kV system supplies about 60% of the total load as shown in Figure 4[5]. The average yearly load growth on the system is 1.7% and there is a total increase of 450 MW over the next twenty years.

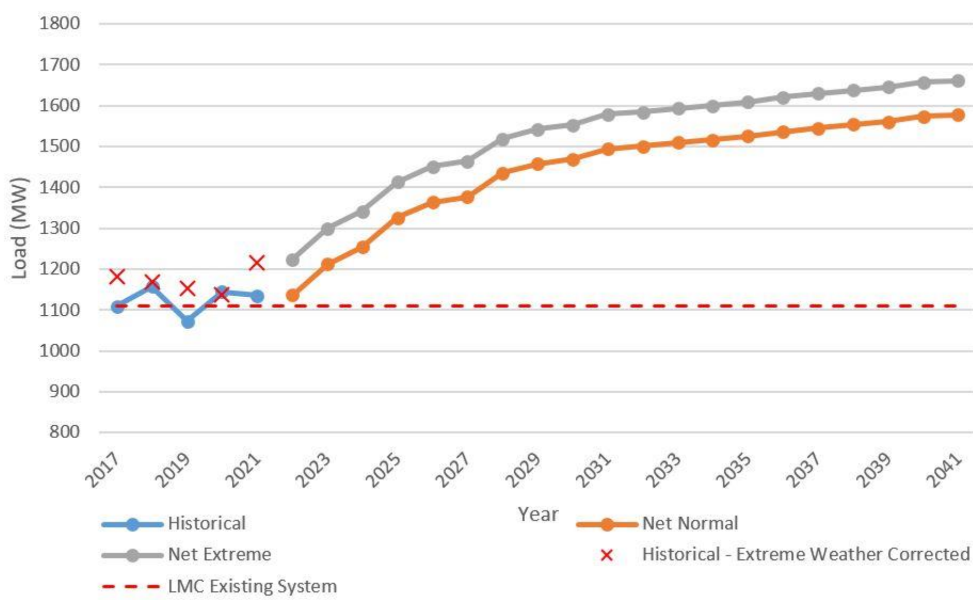

Figure 4. Ottawa 115 kV System Planning Forecast

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[5] More information about the Ottawa 115 kV System transmission issues and load meeting capability are available in section 4.3 of the report.

The annual growth rate for the 115 kV system in the first ten years of the forecast is especially high, at about 2.5%. Compared to the previous regional planning forecast, the load growth on the 115 kV system is significantly higher. The average growth rate from the 2020 Greater Ottawa Regional Infrastructure Plan (RIP) was only 0.70% with a total increase of approximately 175 MW over the same period. The incremental demand is based on currently known information of large distribution connection requests driven by electrification of heating, electric vehicle penetration and other impacts due to net-zero targets.

3.3 Orleans Area Demand Forecast

The demand forecast for the Orleans area consisting of Bilberry Creek TS and Orleans TS is shown in Figure 5 below[6]. The yearly load growth in this pocket is roughly 1.00% per year, with a total increase of 30 MW over the next twenty years.

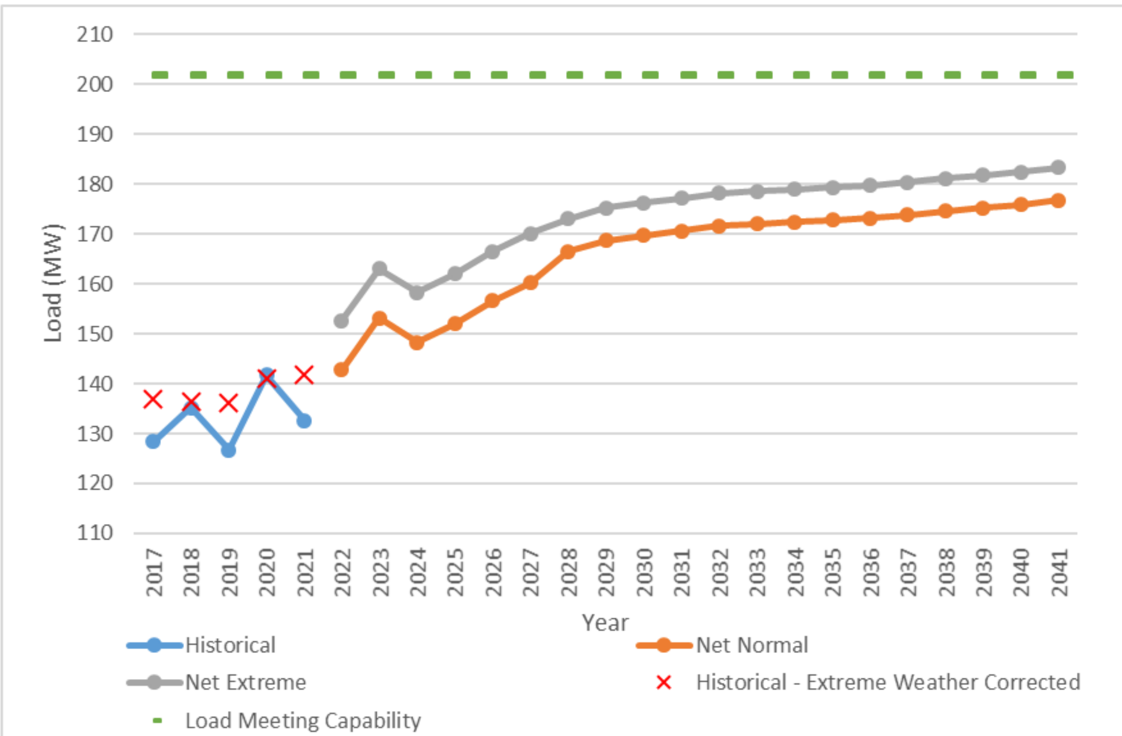

Figure 5. Orleans Area Planning Forecast

[6] More information about the Orleans Area transmission issues and load meeting capability is available in section 4.2 of the report.

3.4 Eastern Ottawa 115 kV System Demand Forecast

In addition to supplying Bilberry Creek TS and Orleans TS, the eastern Ottawa 115 kV system, comprised of transmission circuits A2 and H9A/79M1, supplies an additional 10 supply stations towards the east, as well as the transmission connected customer National Research Council (NRC). Through engagement meetings with NRC, it was learned that there are a number of plans involving the expansion of the facility as well as electrification of heating. There is some uncertainty with regards to NRC's plan to electrify their heating both from a timing and magnitude perspective, as such these plans were not included in the reference forecast and instead were put into the high growth scenario.

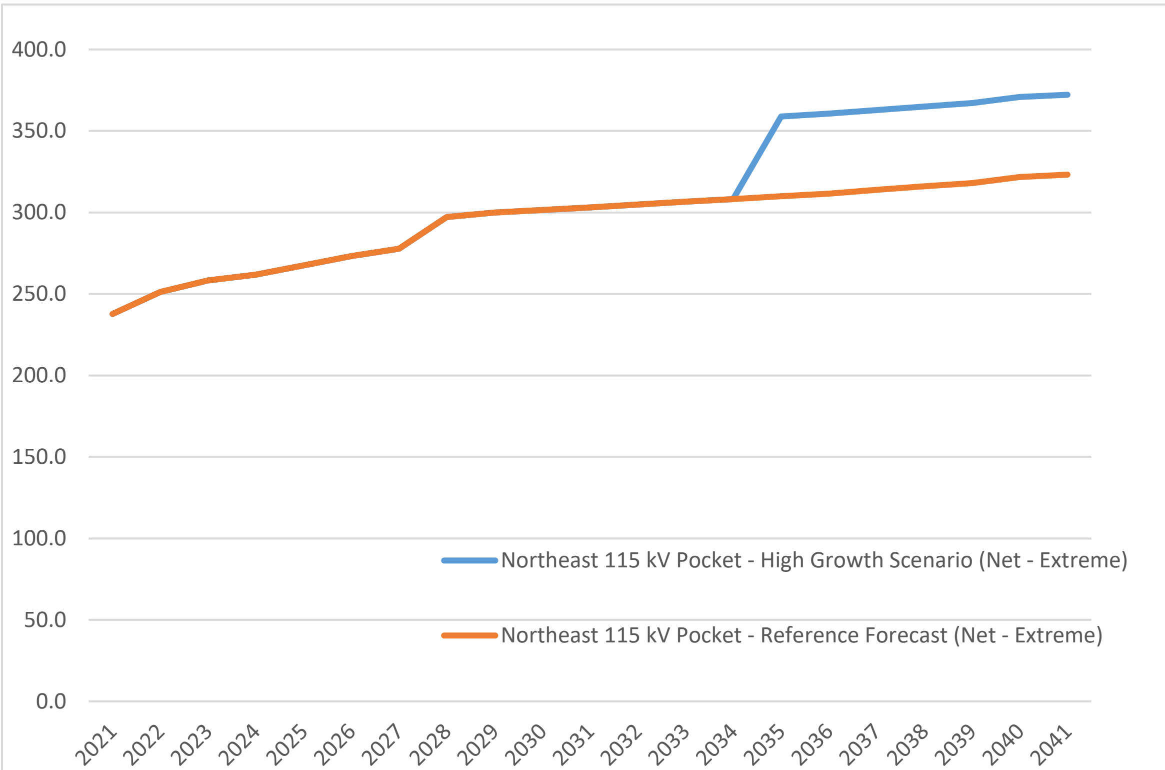

Figure 3. Eastern Ottawa 115 kV System Planning Forecast

3.5 Energy Evolution - Ottawa's Community Energy Transition Strategy

Energy Evolution[7] is the action plan for how the City of Ottawa will meet its targets to reduce greenhouse gas emissions to zero by 2040 within the corporation, and by 2050 Ottawa-wide. Its vision is to transform Ottawa into a thriving city powered by clean, renewable energy. To achieve Ottawa's emission reduction targets will require:

- Significantly reduce energy demand for existing end-uses
- Phase out fossil fuels
- Increase use of renewable resources

[7] More information regarding Energy Evolution is available on the City of Ottawa's website (link)

Some of the identified actions to help achieve these targets will have an interdependency with planning the electricity system supplying the City of Ottawa, such as electrification of personal and commercial vehicles, electrification of heating, and new renewable resources.

The Energy Evolution strategy was approved by Ottawa's City Council on October 28, 2020. The impact of Energy Evolution on the peak electricity demand has yet to be quantified and is not included in the demand forecast shown in Error! Reference source not found.. The IESO will work with the City of Ottawa and the Greater Ottawa regional planning working group during the next cycle of regional planning for Greater Ottawa, which commenced in Q4 2022, to determine how the strategy would impact the development of planning forecasts and scenarios, and what additional planning activities are necessary to support the City of Ottawa's Energy Evolution strategy. It's anticipated that to achieve energy evolution targets, Ottawa demand would grow beyond the high growth scenario and this uncertainty was considered when evaluating options.

4. Transmission Issues

4.1 Bilberry Creek TS End-of-Life

Bilberry Creek TS is a 115 kV connected supply station built in 1976 to supply the Orleans area. The station is owned by Hydro One and supplies distribution customers from both Hydro One and Hydro Ottawa.

Hydro One has indicated that Bilberry Creek TS will reach its end-of-life in the near term and will require substantial refurbishment to continue operation. This issue was examined as part of the 2020 Ottawa Area Sub-region IRRP, and it was recommended that Bilberry Creek TS be replaced like-for-like, as this would allow for sufficient capacity in the Orleans pocket beyond the year 2037. However, in light of recent load growth projections on the Ottawa 115 kV system, there may be alternate solutions that would solve Bilberry Creek TS end-of-life need while also addressing needs on the upstream 115 kV system. These solutions are further described in section 5 of this report.

4.2 Orleans Area Reliability Needs

Orleans Pocket

The Orleans pocket is served primarily by Bilberry Creek TS and Orleans TS. The two stations are in close geographic proximity and can supply local load growth interchangeably. The long-term emergency ratings of Bilberry Creek TS and Orleans TS are 85 MW and 117 MW, respectively, resulting in a combined capacity of 202 MW. The coincident demand forecast shows load in this pocket reaching a maximum of 183 MW in 2041, with Bilberry Creek TS serving 75 MW of load and Orleans TS serving the other 108 MW. This means that the combined capacity in the pocket can sufficiently accommodate the full 20-year demand forecast for the pocket.

Bilberry Creek TS has a maximum non-coincident peak of 81 MW in 2041, while that of Orleans TS is 117 MW. Neither of the stations exceed their individual long-term emergency ratings based on their non-coincident forecasts. While this is the case, there is only 4 MW of remaining capacity at Bilberry Creek TS and zero at Orleans TS by 2041. This can potentially result in challenges with any additional growth in the pocket beyond the reference forecast.

Orleans TS Capacity Need

Orleans TS is a dual element spot network (DESN) type station, a design that consists of two transformers typically supplied by two circuits, one transformer connected to each. The existing configuration of Orleans TS, however, is such that one transformer is connected to 115 kV circuit H9A and the other transformer is connected to 230 kV circuit D5A. Because the transformers are supplied at two different voltages the station must be operated in a way that doesn't parallel the 230 kV and 115 kV systems through the low voltage bus.

With all elements in-service, Orleans TS is ***typically*** supplied by the 115 kV system today. If there is a contingency to the 115 kV circuit H9A, supply will be restored to affected customers via the 230 kV circuit D5A through an automatic load transfer scheme. However, the 115 kV supply to Orleans TS is insufficient to accommodate the forecasted peak demand of the station. As such, during periods of peak demand, Orleans TS is operated in a way where the station load is divieded between the two supply points pre-contingency.

The 2015 IRRP noted that although this supply configuration is acceptable, regional planning should consider potential opportunities to convert this station to a typical DESN configuration in conjunction with addressing other reliability needs in the vicinity. At the time Orleans TS was constructed, 115 kV circuit H9A was built ready for conversion to 230 kV operation; however, presently it operates at 115 kV.

The study forecast for Orleans TS anticipates it will be loaded to the planning capacity level of 117 MW by 2041.

Voltage Regulation on 115 kV Circuit 79M1

The 115 kV circuit 79M1 supplies Rockland DS, Rockland East DS, Clarence DS, Wendover DS, and Hawkesbury MTS. The 79M1 circuit is supplied from Hawthorne TS via circuit H9A. Total distance from Hawthorne TS to Hawkesbury MTS (last station on 79M1) is approximately 80km. As a result of this long distance and circuit loading, lower voltage can be expected at the end of the line. The post-contingency voltage at Hawkesbury MTS will drop below the minimum voltage criteria within the next five years. While not the primary contributor, the Orleans area load fed from H9A exacerbates the problem.

4.3 Ottawa 115 kV System Capacity

The Ottawa 115 kV system is supplied by a total of six 230-115 kV autotransformers; four at Hawthorne TS, on the east side of the City, and two at Merivale TS, on the west side. A large number of stations in the Ottawa Area Sub-region, including nearly all of the stations located within the Greenbelt, are supplied by this 115 kV transmission system, which also includes a number overhead transmission lines as well as underground cables supplying downtown Ottawa.

Forecast demand growth on the 115 kV system is increasing the power flow through the 230-115 kV auto-transformers at both Hawthorne TS and Merivale TS to the point where they are exceeding their load meeting capability. The Orleans Area Study forecast shows a number of 115 kV supplied stations are currently being operated at or near their station capacity. Notwithstanding other station limitations, the potential to expand these stations, or to connect new stations will be limited by the load meeting capability of the 115 kV system as a whole. As a recommendation from the 2020 Ottawa Area Sub-region IRRP, the IESO triggered a study of the Ottawa 115 kV System in 2021. The study is yet to be completed, and with new cycle of IRRP having started (March 2023), the study of the Ottawa 115 kV System will continue as part of the this IRRP.

Preliminary results indicate that the load meeting capability of the Ottawa 115 kV system (1110 MW) is insufficient in accommodating today's load. The limiting phenomena for the Ottawa 115 kV system is thermal overload of Merivale TS auto-transformer T22 with two elements out of service (Merivale TS T21 and 115 kV circuit A3RM). The draft recommendation to address this limitation involves:

- Replace existing Merivale T22 which is nearing EOL (resulting in higher long term emergency rating)
- Install third auto-transformer at Merivale TS
- Utilization of load rejection/shedding of up to 150 MW in Ottawa
- Pursue system cost effective energy efficiency in Ottawa (up to 50 MW)

With the above improvements in place, the Ottawa 115 kV system LMC will improve to 1329 MW. By pursuing the identified system cost effective EE in the Ottawa area, the Ottawa 115 kV system is expected to be able to accommodate the full 20-year demand forecast based on the 2020 Regional Infrastructure Plan forecast for Greater Ottawa. However, with the higher Orleans Area Study forecast, supply capacity issues may appear as early as 2025 and necessitate additional investments into the Ottawa 115 kV system. This need will be further assessed and final recommendations will be made in the current cycle of the Ottawa Area IRRP.

5. Analysis of Alternatives

5.1 Alternatives

This study compares alternatives to meet the identified near-, mid-, and long-term supply capacity and transmission asset renewal requirements in the Orleans Area. Non-wire alternatives such as gas generators, battery storage, and energy efficiency programs are not feasible stand-alone options to address the end-of-life refurbishment need of a fully loaded supply station. As such, transmission alternatives are being considered to address the identified needs, and where appropriate, complimentary non-wires solutions can be considered.

Two primary alternatives were evaluated in this study:

1. Refurbishment of Bilberry Creek TS – by refurbishing Bilberry Creek TS, this option primarily maintains the existing electricity supply to the Orleans area.
2. Decommission and Replace Bilberry Creek TS – this option involves expanding the 230 kV supply into the Orleans area and enabling the connection of a new 230 kV supply station and the upgrade of existing Orleans TS. There are two variations to how the 230 kV expansion into the Orleans area can be achieved, both of which are examined in this study.

Alternative 1: Refurbishment of Bilberry Creek TS

This alternative was previously recommended in the 2020 Ottawa Area IRRP to address the transmission refurbishment need at Bilberry Creek TS and the capacity need at Orleans TS. The alternative involves the like-for-like refurbishment of the Bilberry Creek TS which primarily includes replacing two step-down transformers, replacing the majority of the low voltage breakers, and installing a new protection and control building.

This alternative will also require two new distribution feeders be build at Bilberry Creek TS to enable Hydro Ottawa to supply up to 28 MW of additional load in the area.

As noted in section 4.2, the Orleans area load supplied from circuit H9A exacerbates the voltage regulation problem at the end of the 79M1 circuit near Hawkesbury MTS. Thus, by refurbishing Bilberry Creek TS, the voltage regulation problem will remain, and additional reactive support will be required along 79M1 in the near-term to address post contingency voltage violations at Hawkesbury MTS.

Alternative 1 is effectively "status quo", it addresses the asset renewal need at Bilberry Creek TS and maintains the existing Orleans area supply capacity of approximately 200 MW, which sufficiently accommodates the 20-year demand forecast. However, maintaining the area's current supply capacity will limit future growth in the Orleans area as there is only 20 MW of remaining capacity available.

Alternative 2: Decommission and Replace Bilberry Creek TS

This alternative involves decommissioning Bilberry Creek TS and replacing the station with a new 230 kV connected supply station in the area. Connecting this new supply station, Brian Coburn MTS, will require expansion of the 230 kV supply into Orleans. The expansion involves a new 230 kV transmission circuit be constructed from Hawthorne TS to Orleans TS. The new 230 kV connected supply station will have a capacity of 100 MW, an increase of approximately 15 MW.

In this alternative, Orleans TS will be upgraded from its current two voltage supply via 115 kV circuit H9A and 230 kV circuit D5A, to having a proper dual 230 kV supply from Hawthorne TS. As part of this upgrade, transformer T1 at Orleans TS will need to be replaced with a new 230-27.6 kV step-down transformer. Now with a proper dual 230 kV supply, the upgraded Orleans TS will have an improved station capacity of 153 MW, an increase of approximately 35 MW.

The combined capacity of Brian Coburn MTS and the upgraded Orleans TS of 250 MW sufficiently accommodates the 20-year demand forecast, and provides approximately 65 MW of additional capacity for future growth.

By reducing the loading on 115 kV circuit H9A, alternative 2 also mitigates the voltage violations at Hawkesbury MTS and the need for installing additional voltage support along circuit 79M1.

In conjunction with a third auto-transformer at Merivale TS, the conversion of the Orleans area helps in deferring additional investments on the Ottawa 115 kV system. These additional investments may include additional auto-transformers at Hawthorne, new transmission lines into Merivale TS, additional energy efficiency, and/or non-wires solutions. The demand forecast developed for the Orleans Area Study indicates that the loading on the Ottawa 115 kV system is significantly higher then the previous 2020 Regional Infrastructure Plan forecast. As part of the current cycle of the Ottawa IRRP, the TWG will confirm the Ottawa 115 kV System demand forecast, the network benefits of the conversion of Orleans Area, and the long-term plan for the Ottawa 115 kV System.

The expansion of the 230 kV system in Orleans can be achieved in two ways, as outlined in the following variations.

Variation A

In this variation, a portion of the 115 kV circuit H9A, which currently supplies Orleans TS, would be converted to 230 kV. Specifically, the portion from Hawthorne TS to Orleans TS would be converted, allowing for Orleans TS and the new supply station to be supplied by two 230 kV circuits (D5A and the newly converted H9A).

All other existing loads connected onto H9A, A2, and 79M1 will now be supplied by A2. With two transmission lines serving the area today, A2 and H9A can be tied together via switching at Bilberry Creek TS to maintain supply to loads during outage conditions, and restore loads after contingency events.

In this variation, new switching facilities will be installed at Cyrville JCT, about 1.85 km from Cyrville MTS to allow A4K and A2 to be tied together. While A4K cannot fully resupply the forecasted peak demand of A2, the switching is needed to facilitate outage planning at Hawthorne TS and will significantly aid in load restoration.

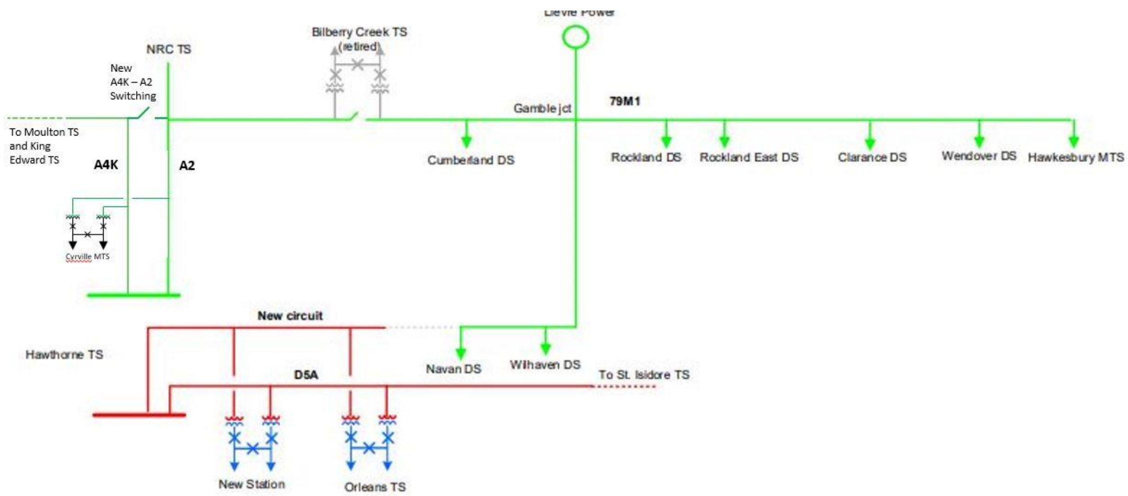

Figure 7: Single Line Diagram of the Orleans Pocket for Variation A

Variation B

In this variation, H9A would be left as a 115 kV circuit, and instead a new 230 kV circuit would be added to existing structures between Hawthorne TS and Orleans TS. In this variation, the supply to existing customers on H9A, A2, and 79M1 remains the same.

H9A also provides connection to Lièvre Power LP, a 250 MW hydro-electric generator located in Quebec. In addition to H9A, Lièvre Power is also connected to 230 kV circuit D5A. Only one of the H9A or D5A interconnections to Lièvre Power may be in service at a time, Lièvre Power is typically connected to D5A.

Due to short circuit limitations of the Hawthorne 115 kV strain bus, H9A connection to Lièvre Power is not allowed today. Upgrades at Hawthorne TS are in progress and this limitation is expected to be resolved in the near future.

Transfers from Lièvre Power are constrained by thermal overload on H9A. Maintaining the existing 115 kV system ensures the existing import capability of Lièvre Power generation over H9A is maintained. The summer LTE ratings of the limiting circuit sections between Lièvre Power and Bilberry creek (490 A) are significantly lower then that of the sections between Lièvre Power and Orleans (1060 A). Transfer limits over H9A and A2 have not been calculated and will need to be confirmed.

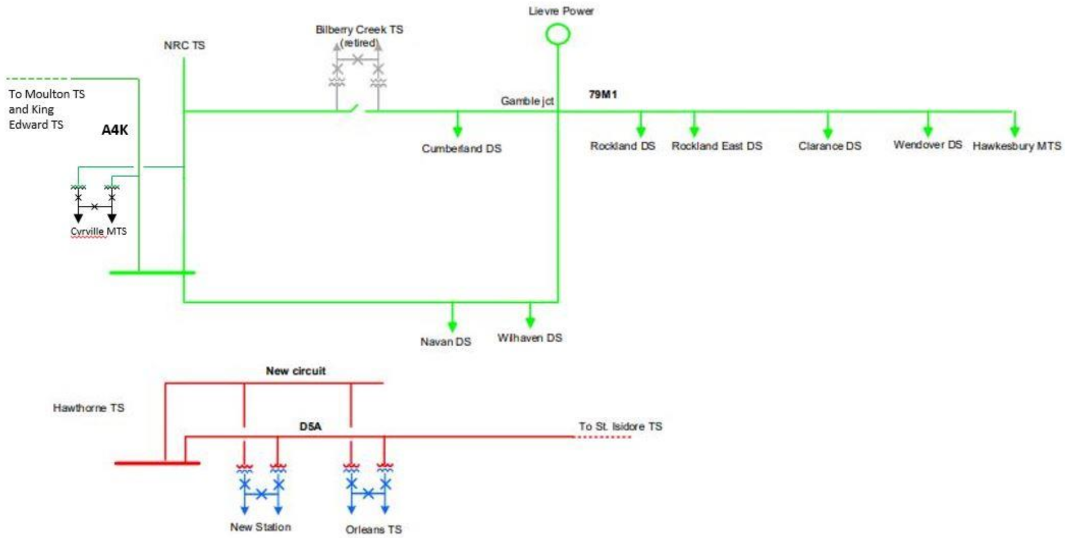

Figure 8: Single Line Diagram of the Orleans Pocket for Variation B

5.2 Comparison of Alternatives

Both alternatives assessed accommodates the 20-year demand forecast for the Orleans area. While Alternative 1 is the least cost option, Alternative 2 - Variation B is preferred for the following reasons:

- By transferring approximately 150 MW of load from the 115 kV to the 230 kV transmission system in addition to installing a third auto-transformer at Merivale TS and deploying load rejection/shedding, the 115 kV system capacity need would be deferred from 2025 to 2038 based on the current demand forecast, which would defer the need for additional investments such as a new transmission line into Merivale TS, additional auto-transformers at Hawthorne TS, and upgrades to the 115 kV circuits between Hawthorne and Merivale. The 115 kV system forecast and capacity need will be further studied and confirmed in the current Ottawa Area IRRP. By targeting up to 25 MW of additional system cost effective energy efficiency programs in the area, the capacity would be deferred beyond the full 20-year demand forecast.[8]
- By upgrading Orleans TS and the 230 kV supply to the station, it will provide approximately 35 MW of incremental station capacity that may be needed if the forecasted demand is higher than the reference forecast (i.e. high growth decarbonization forecast scenarios materialize). The Orleans TS upgrade will also remove the need for the Automatic Load Transfer Scheme that presently exists at the station, which will simplify operating of the Orleans area and also improve the reliability of service for customer loads at the station by reducing outage durations for certain contingencies.

[8] The Gatineau Corridor EOL Study also made recommendations to pursue energy efficiency in the Ottawa region (up to 230 MW). As the 115 kV is a contained within the broader Ottawa region, targeting energy efficiency on the 115 kV system would benefit both systems.

- By upgrading existing transmission lines to incorporate a new 230 kV circuit from Hawthorne TS to Orleans TS, the existing 115 kV system configuration to the Orleans area and the area further east towards Hawkesbury is maintained, thus also maintaining the existing level of reliability to the existing customers in the area.

A more detailed comparison of the two options is shown in Table 1.

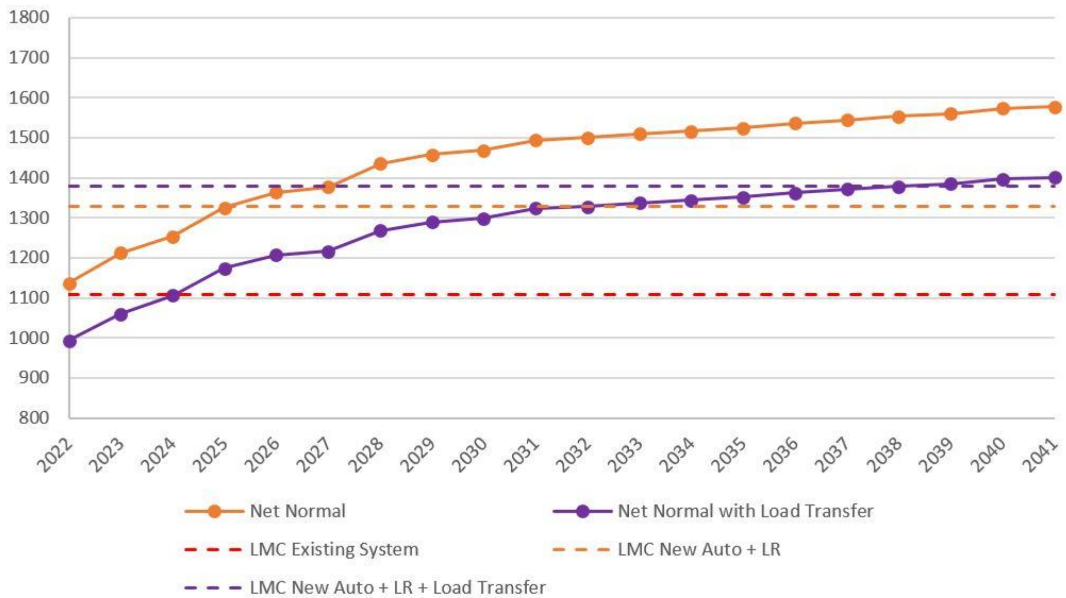

Figure 9: Ottawa 115 kV System Load Meeting Capability

Table 1. Comparison of Alternatives

	Option	Needs Resolved	Resulting Capacity in the Orleans Pocket	Option Benefits /Risks	Cost
1	Refurbish Bilberry Creek TS, and Provide Two Additional Feeder Positions for Hydro Ottawa	Bilberry Creek TS asset renewal	Total Capacity: 202 MW	Retains a second supply point (backup) for customers supplied by H9A/79M1/A2. Orleans area loads will continue to be served by the Ottawa 115 kV system. Not moving this load to the 230 kV system now may result in the need for costlier investment on the Ottawa 115 kV system in the future to	Total Cost: $62.82 M

				accommodate load growth on the 115 kV System.	
2	Retire Bilberry Creek TS, convert Orleans TS to dual 230 kV supply, and add an additional station (Brian Coburn MTS) on the 230 kV system	Bilberry Creek TS asset renewal Defer 115 kV system supply capacity need	Total Capacity: 250 MW	Orleans TS is upgraded to a standard dual supply station, avoiding the need for the Orleans TS Automatic Load Transfer Scheme, which will improve the quality of supply to customers by mitigating the short outages resulting from the operation of the scheme. In addition to improving the quality of supply to customers, removing the scheme will also help to simplify the operation of the system. Orleans area loads will be transferred from the 115 kV system to the 230 kV system, which may result in mitigating or deferral of forecast needs on the broader Ottawa 115 kV system. Provides additional capacity to accommodate further load growth in the area beyond currently forecast levels. Variation A. Leverages existing 115 kV line, H9A, which is ready to be converted to 230 kV instead of building a new 230 kV line (higher cost); however, to maintain reliability, additional A2/A4K switches are required as part of this variation. Variation B. By retaining the existing 115 kV circuit H9A: -Existing system reliability will be maintained (i.e. maintaining or restoring load during certain outages) -Existing supply capacity of H9A/79M1 will be maintained to accommodate for future load growth beyond currently forecast levels -Existing import capability from Quebec on H9A will be maintained.	Variation A Total Cost: $71.1 M Variation B Total Cost: $75.4 M

6. Conclusions and Recommendations

To mitigate forecast risk associated with high growth scenarios (i.e. electrification), preserve options to increase station supply capability in the future, maintain existing level of reliability to existing customers, defer the need for additional upgrades to the Ottawa 115 kV system beyond the third auto-transformer at Merivale TS, and maintain the existing import capability from hydro-electric generation from Lièvre Power LP onto 115 kV circuit H9A, the following integrated solution package is recommended to address the transmission asset refurbishment needs at Bilberry Creek and capacity needs at Orleans TS over the long-term:

- Decommission Bilberry Creek TS
- Upgrade D5A/H9A transmission line to carry an additional 230 kV circuit from Hawthorne TS to Orleans TS
- Upgrade Orleans TS to accommodate two 230 kV supply circuits
- New 230 kV supply station in the Orleans area
- Pursue up to 25 MW of additional system cost-effective energy efficiency in the Ottawa 115 kV system area over the 20 year planning horizon

This solution package is estimated to cost approximately $75 M. The included reinforcements ensure reliability in the Orleans area is sufficient for the next 20 years, and provides an additional 65 MW of additional capacity beyond the demand forecast for future growth.

This solution package will also result in avoided re-investments into the EOL replacement of Bilberry Creek TS, network benefits to the upstream Ottawa 115 kV System[9], and continued import capability from Lièvre Power LP connected on H9A.

[9] Transferring load from the 115 kV to the 230 kV system will inherently defer the forecast capacity needs on the 115 kV system based on the Orleans Area Study demand forecast. The benefit (timing and value) will be confirmed as part of the current cycle of Ottawa Area Sub-region IRRP.

Appendix A – Planning Assessment 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; and
- 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 bulk report 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 report 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; and
- Support sector policy and decision making.

There are various reliability standards which, as the electricity system planner and operator, the IESO is obliged to meet. NERC and NPCC membership requires 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 to meet 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 Ontario Resource and Transmission Assessment Criteria (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, facilitate 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.

Appendix B – Load Forecast and Supply Need Data

The following datasets are included in this section and are also available in the excel file provided:

- Greater Ottawa peak demand forecasts
- Table 2: Total coincident net extreme and normal-weather corrected reference forecasts
- Ottawa 115 kV System
- Table 3: Total coincident net extreme and normal-weather corrected reference forecasts
- Orleans area demand forecasts
- Table 4: Total coincident net extreme and normal-weather corrected reference forecasts
- Ottawa Eastern 115 kV System:
- Table 5: Total coincident net extreme-weather corrected reference and high growth forecasts

Table 2 | Total Coincident Greater Ottawa Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Net Normal	1859	1970	2040	2130	2183	2218	2289	2329	2373	2422	2449	2484	2512	2525	2545	2563	2578	2593	2610	2619
Net Extreme	1996	2107	2177	2267	2320	2355	2423	2463	2507	2556	2583	2618	2645	2658	2679	2696	2712	2726	2744	2752

Table 3| Total Coincident Ottawa 115 kV System Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Net Normal	1137	1213	1255	1326	1364	1377	1436	1458	1470	1495	1500	1510	1517	1525	1537	1546	1554	1561	1574	1578
Net Extreme	1224	1300	1342	1413	1451	1464	1519	1542	1553	1578	1584	1593	1600	1609	1620	1629	1638	1645	1657	1662

Table 4 | Total Coincident Orleans Pocket Peak Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Net Normal	143	153	148	152	157	160	167	169	170	171	172	172	172	173	173	174	175	175	176	177
Net Extreme	153	157	159	163	168	172	177	180	182	183	187	187	187	187	188	189	189	190	191	191

Table 5 | Total Coincident Eastern 115 kV System Demand Forecast (MW)

Forecast Scenario	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Net Extreme (reference)	251	258	262	267	273	278	297	300	302	303	305	307	308	310	312	314	316	318	322	323
High Growth	251	258	262	267	273	278	297	300	302	303	305	307	308	359	361	363	365	367	371	372

Appendix C – Technical Study Results

Option 2, Variation A: Technical Study Violations

The variation A configuration was tested to determine feasibility. The results of these studies are summarized in table 6 below.

Table 6. Option 2, Variation A Violations

Year	System Details	All Elements	D5A Out	New 230 kV circuit Out	B5D Out
2022	Orleans: 90MW, 20MX Brian Coburn: 56MW, 20MX Ottawa Demand: 1953MW	No violations	No violations	No violations	No violations
2030	Orleans: 103MW, 20MX Brian Coburn: 72MW, 20MX Ottawa Demand: 2500MW	No violations	No violations	No violations	No violations
2041	Orleans: 108MW, 20MX Brian Coburn: 74MW, 20MX Ottawa Demand: 2700MW	No violations	No violations	No violations	No violations

Given the above results, Option 2, Variation A causes no addition violations or issues and thus does not make the system in the Orleans pocket worse.

Option 2, Variation B: Technical Study Violations

The variation B configuration was tested to determine feasibility. The results of these studies are summarized in table 7 below.

Table 7. Option 2, Variation B Violations

Year	System Details	All Elements	D5A Out	New 230 kV Circuit Out	B5D Out
2022	Orleans: 90MW, 20MX Brian Coburn: 56MW, 40MX Ottawa Demand: 1953MW	No violations	No violations	No violations	No violations
2041	Orleans: 120MW, 40MX Brian Coburn: 83MW, 20MX Ottawa Demand: 2700MW	No violations	No violations	No violations	No violations

Given the above results, Option 2, Variation B causes no addition violations or issues and thus does not make the system in the Orleans pocket worse.

FIO Study: Option 2, Variation A and Variation B

The impact of Variation A and Variation B on the Flow into Ottawa (FIO) interface were also studied and documented, to further determine the feasibility of the two configurations.

A previous Ottawa study (Gatineau Corridor end-of-life) established that the load meeting capability of the Ottawa system is limited to 1800MW (after 150MW of load rejection) when both X522A and X523A are out. The study produced a PV curve that shows when the voltage collapse occurs, which is shown in figure 12 below.

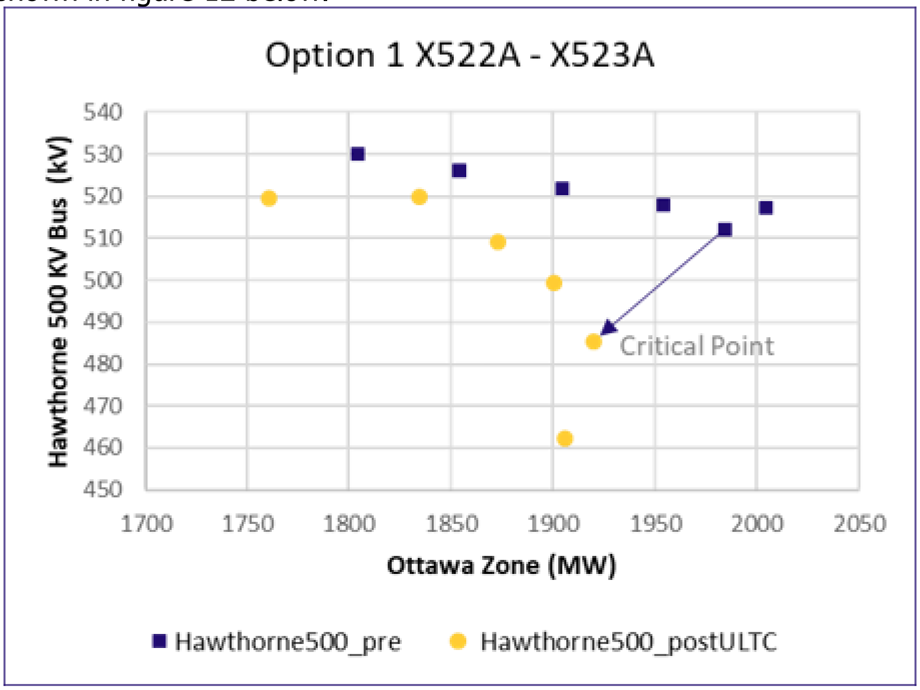

Figure 12. PV curve for current day system

The Orleans study tested the impact on the FIO interface for Variation A and B by producing similar PV curves. The PV curves are shown below.

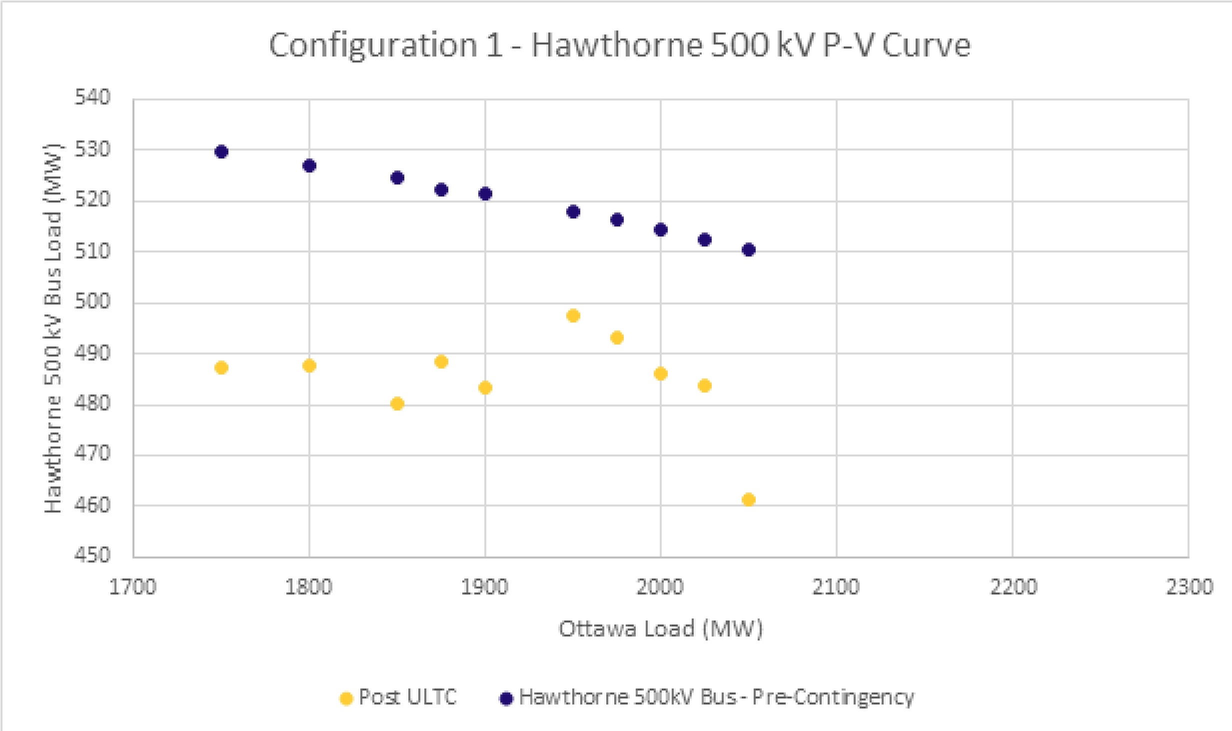

Figure 13. PV curve for Variation A configuration

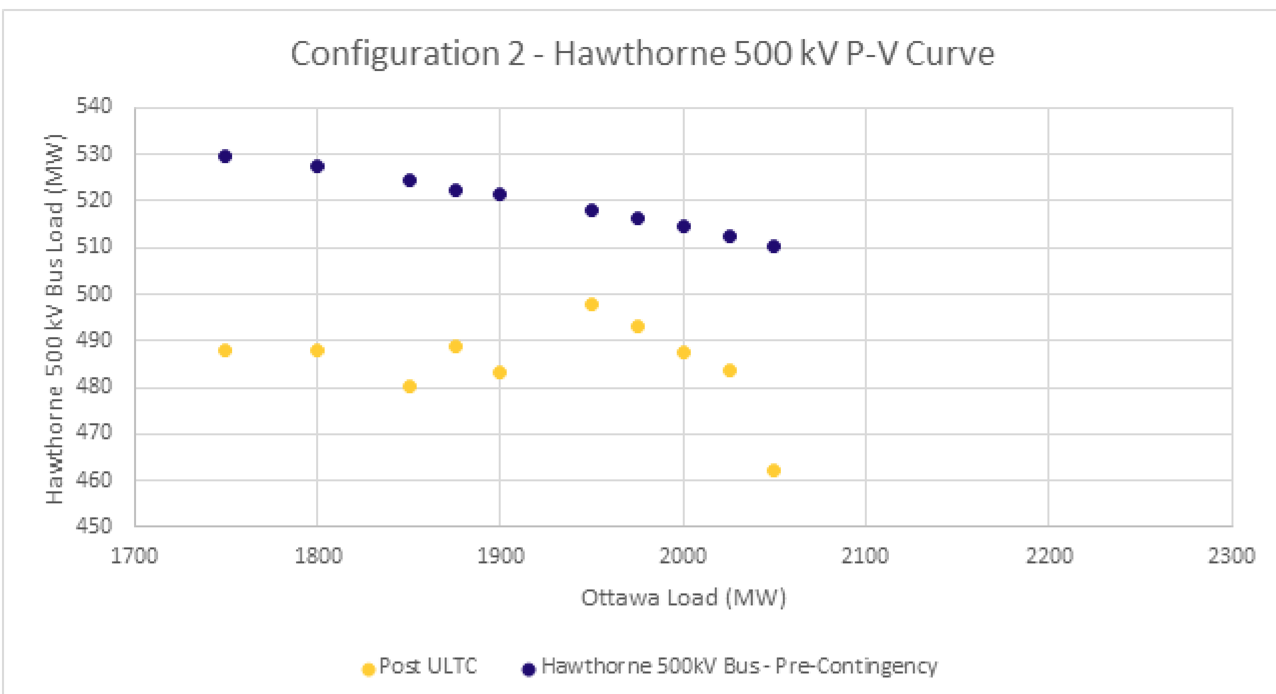

Figure 14. PV curve for Variation B configuration

From the above graphs, it can be seen that with Variation A and Variation B configurations, the FIO interface has a limit of approximately 1900 MW. This is the same limit identified using the current system configuration in the Gatineau Study. Thus, the proposed changes for both variations do not negatively impact the FIO limitation.

115 kV System Study: Variation A and Variation B

The impacts of the Orleans area reconfiguration on the Ottawa 115 kV System LMC are shown in the table below.

Initial Condition	Load Rejection	Contingency	Limiting Element	New Merivale Auto plus Orleans Reconfiguration Limit (MW)	New Merivale Auto Limit (MW)	Existing System Limit (MW)
All Elements in Service	No	N/A	Merivale T21	1690	1545	1395
All Elements in Service	No	Merivale T21	Merivale T22	1753	1805	1315
1 Element Out of Service	Yes	M31A or M30 outage	Hawthorne T9	1379	1329	1110
All Elements In Service	Yes	Merivale T22 + A3RM	Merivale T21	1760	1805	1110

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OEB STAFF INTERROGATORY - 05

Reference:
Exhibit B-5-1, Pages 1-2

Preamble:
According to Reference 1, Alternative 1, which consists of modifying the existing double-circuit transmission line towers to support a third circuit, would have presented challenges due to transmission line galloping, structural foundation reinforcement, and outage management.

Interrogatory:

a) Under Alternative 2, Hydro One Networks' preferred alternative, the new single-circuit 115 kV transmission line will be built within an existing right-of-way shared with two existing 230 kV double-circuit transmission lines. What is the overall width of the shared right-of-way? Please provide Hydro One Networks' assessment of any galloping concerns between the adjacent circuits under the preferred alternative.

b) Please provide the higher compression and uplift forces resulting from adding a third circuit to the existing structures in Alternative 1, as well as the design loads of the existing structure foundations.

c) Does Alternative 2 require the use of temporary bypass line arrangements? Please explain how it is preferable over Alternative 1 in this regard.

Response:

a) The existing right-of-way, which is shared by the two existing 230 kV double-circuit transmission lines, is generally 100 m in width, with the exception for a short segment where the lines terminate into Hawthorne TS, as shown in **Attachment 1 of Exhibit E, Tab 1, Schedule 1**.

   Under the preferred Alternative 2, the new 115 kV transmission line would be constructed on separate structures from the existing 230 kV transmission lines, unlike Alternative 1. Further, the 115 kV circuit under Alternative 2 is positioned significantly lower vertically relative to the 230 kV circuits and is separated from them by a greater horizontal distance than under Alternative 1. This increased electrical and physical separation substantially reduces the potential for conductor interaction. Accordingly, no galloping-related concerns are anticipated between the 115 kV and 230 kV circuits under the preferred Alternative 2 configuration.

b) Alternative 1 was only assessed at the feasibility stage and was not advanced to detailed design. The feasibility assessment considered the implications of adding a third circuit to an existing 230 kV double-circuit transmission line. The addition of a third circuit would be expected to materially increase the loading on the existing structures and foundations. Based on the magnitude of the additional circuit loading, the assessment concluded that structural strengthening of the towers and reinforcement of the foundations would likely be required at many, if not most, locations along the line.

As described in **Exhibit B, Tab 5, Schedule 1**, Alternative 1 was deemed to be an unviable alternative based on several technical reasons and was therefore screened out during the feasibility assessment stage. Given that the alternative was not advanced beyond the feasibility stage, detailed structural loading calculations and foundation design assessments were not undertaken. Consequently, detailed engineering analysis and information on specific compression forces, uplift forces, and foundation design loads are not available.

c) Yes, Alternative 2 requires the use of a temporary bypass; however, this arrangement would be limited to Orleans TS and consists of utilizing a Mobile Transformer Unit (MTU) while the station bay upgrades are completed. In contrast, Alternative 1 would require extensive modifications to the existing transmission towers, requiring multiple extended outages subject to very short outage recall times. Accordingly, Alternative 1 would require a temporary bypass extending the full length of the transmission corridor between Hawthorne TS and Orleans TS to ensure reliable supply during these modifications. Therefore, the temporary bypass associated with Alternative 1 would be significantly more complex and disruptive than the temporary bypass required for Alternative 2.

OEB STAFF INTERROGATORY - 06

Reference:

Exhibit B-5-1, Pages 2-4

Preamble:

According to Table 1 and Table 2 of Reference 1, the net capital cost for 1443.7 kcmil ACSR/TW conductor is $52.945 million, compared to $51.880 million for 1033.5 kcmil ACSS/TW conductor, a difference of $1.065 million. However, the net present value of 1443.7 kcmil ACSR/TW conductor is more favourable over a 50-year time horizon due to reduced line losses.

Interrogatory:

a) Other than the difference in material procurement costs of the two conductor alternatives in Table 1 and Table 2 of Reference 1, what other factors contribute to the difference in their net capital cost ($1.065 million)?

b) Please provide the calculation showing how the $164,052/MW capacity price used in Table 2 of Reference 1 was derived. Which year's IESO capacity auction results is this calculation based on?

c) Would the following conductor size alternatives meet the supply capacity needs in the Orleans area and continue to maintain the interconnection power exchange capability?
   i. 1192.5 kcmil ACSR
   ii. 1780 kcmil ACSR/TW

d) Please supplement the conductor size alternative analysis in Reference 1 by including 1192.5 kcmil ACSR and 1780 kcmil ACSR/TW as additional alternatives. Please provide the complete calculations for the NPV sensitivity analysis in Microsoft Excel format, including all formulas used, for these two additional alternatives as well as the original two alternatives included in Table 2 of Reference 1.

Response:

a) In addition to the differences in conductor procurement costs, the difference in the net capital cost between the two conductor alternatives presented in Tables 1 and 2 of **Exhibit B, Tab 5, Schedule 1** is attributable to several distinct line design and construction requirements. Specifically, the heavier conductor type requires:
   i. Four additional H-frame structures;
   ii. Taller poles to compensate for increased conductor sag while maintaining required clearances;

iii. Additional guying to accommodate the higher mechanical loading imposed on structures;
iv. Larger conductor hardware and fittings associated with the increased conductor size and weight; and
v. Additional construction efforts related to the installation of the heavier conductor and associated infrastructure.

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

The Capacity Price of $164,052/MW reflects the 2024 Capacity Auction Reference Price of $651 per MW-business days as noted in the IESO's Capacity Auction[2], which is then annualized by multiplying by business days (assuming 252 business days in a year), as shown below.

Capacity Price = $651/MW-business days x 252 business days = $164,052/MW

c) The 1192.5 kcmil ACSR conductor size does not meet the supply capacity needs as identified by the IESO. While the 1780 kcmil ACSR/TW conductor size is capable of meeting the supply capacity needs, it cannot be accommodated within the current Project constraints, specifically construction of the new transmission line within the existing corridor located between two existing 230 kV double-circuit transmission tower lines.

d) The conductor analysis provided at **Exhibit B, Tab 5, Schedule 1** is predicated on the conductor meeting the supply capacity needs identified by the IESO and being an optimal conductor size to complete the Project. For the reasons provided in response to part c) above, the proposed conductors fail to satisfy those prerequisites and thus the requested information is not provided. The calculations for the NPV Sensitivity Analysis for the two alternatives presented in Table 2 of **Exhibit B, Tab 5, Schedule 1** are provided in MS Excel workbooks and are referred to as Attachment 1 to this Schedule. Attachment 1 has been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

[1] https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Transmission-Planning-Guideline-Transmission-Losses.pdf
[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/cae/cae-20240725-engagement-presentation.pdf

ATTACHMENT 1 – HYDRO ONE'S LINE LOSSES – NPV SENSITIVITY ANALYSIS – CONFIDENTIAL EXCELS

The NPV Sensitivity Analysis models for Alternative 1 and Alternative 2 of the conductor size alternative line loss analysis, presented in **Exhibit B, Tab 5, Schedule 1**, have been filed as 'live' MS Excel spreadsheets and have been filed confidentially with the OEB in accordance with its Practice Direction on Confidential Filings.

OEB STAFF INTERROGATORY - 07

Reference:

1. Exhibit B-7-1, Pages 1-3
2. 2020 Ottawa Sub-Region IRRP, Pages 66-71
3. OEB Filing Requirements for Electricity Transmission Applications, Pages 19-20

Preamble:

According to Reference 2, the alternative to retire Bilberry Creek TS and convert Orleans TS to a dual 230 kV supply was estimated to cost $21 million in 2020. According to Reference 1, the cost estimate has increased to $99.9 million.

Interrogatory:

a) Please explain the cost difference between the 2020 IRRP and the 2026 Class 3 estimate, identifying the different factors that contributed to the cost escalation.

b) Table 1 of Reference 1 includes $4.535 million in cost contingencies for the lines work of the Project and Table 2 of Reference 1 includes $5.597 million in cost contingencies for the stations work of the Project. Does the -20%/+30% confidence range of the Class 3 estimate apply to the project costs before or after the inclusion of the cost contingencies included in Table 1 and Table 2 of Reference 1?

c) Does the Allowance for Funds Used During Construction in Table 1 and Table 2 of Reference 1 correspond to the Capitalized Interest in Table 2 of Reference 3?

Response:

a) The proposed Project, as described in the Application, was not contemplated during the development of the 2020 IRRP. As described in **Exhibit B, Tab 1, Schedule 3, Attachment 1**, significant demand growth across the City of Ottawa following the release of the 2020 IRRP prompted the Greater Ottawa Technical Working Group to initiate a mid-cycle re-evaluation of the 2020 IRRP recommendations for the Orleans area. As a result of that assessment, the previously recommended plans for the Orleans area were not advanced. Instead, a new integrated solution was developed to address the area's future electricity needs reliably and efficiently. This solution was subsequently incorporated into the 2025 IRRP, which emphasized the necessity of expanding supply capacity, of which the proposed Project is a core component. Given that the Project was not contemplated in the 2020 IRRP, no cost estimate for the Project is included in the 2020 IRRP. Consequently, a comparison to the Class 3 cost estimate provided in **Exhibit B, Tab 7, Schedule 1** cannot be undertaken. While the proposed Project was subsequently identified in the 2025 IRRP, that report likewise did not include a cost estimate for the proposed Project. The 2026 RIP, however, included an estimated cost of approximately $100 million for the proposed Project, in line with the cost presented in this Application, as part of a total integrated solution cost estimate of $165 million that reflected both the cost of the proposed Project and Hydro Ottawa's Mer Bleue MTS project.

b) The Class 3 estimate accuracy range of -20% / +30% applies to the Project's total estimated capital cost, inclusive of the cost contingencies identified in Table 1 ($4.535 million for the lines work) and Table 2 ($5.597 million for the stations work) of **Exhibit B, Tab 7, Schedule 1**.

c) The Allowance for Funds Used During Construction in Table 1 and Table 2 of **Exhibit B, Tab 7, Schedule 1** corresponds to the Capitalized Interest in Table 2 of the OEB's Chapter 4 Filing Requirements.

OEB STAFF INTERROGATORY - 08

Reference:

Exhibit B-7-1, Pages 8-11

Preamble:

Reference 1 compares the estimated cost of the stations components of the Project against comparable stations projects.

Interrogatory:

a) According to Table 4 of Reference 1, the work at Hawthorne TS involves the installation of only one 230 kV circuit breaker, while the comparable projects include two to three 230 kV circuit breakers within their scope. Please update Table 4 of Reference 1 by including an adjustment factor for the number of circuit breakers within the scope of the projects.

Response:

a) As outlined in **Exhibit B, Tab 7, Schedule 1**, the unit cost comparison methodology and inferences applied to line work cannot always be achieved for station work. The actual costs of comparable projects are based on project-specific designs and configurations. Accordingly, adjusting station costs based on the number of breakers would require re-engineering the comparator project to exclude the entire breaker position assembly, including the breaker and all associated equipment and infrastructure, such as bus work, foundations, grounding systems, breaker disconnect switches, breaker protections, and related components. Any resulting adjustment would therefore be based on estimated costs rather than the actual costs incurred to construct the comparable project, which would be inconsistent with the OEB's filing requirements[1].

[1] OEB Chapter 4 Leave to Construct Filing Requirements – Section 4.3.2.8, p.23.

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OEB STAFF INTERROGATORY - 09

Reference:

1. Exhibit B-9-1, Pages 1-18
2. EB-2021-0110 Application, Exhibit H-2-1, Pages 27-28
3. Transmission System Code (TSC), Section 6.7.2
4. TSC, Section 6.7.2A

Preamble:

According to Reference 1, the Project will have a positive present value to the network rate pool.

Interrogatory:

a) Does the load forecast in Table 1 of Reference 1 represent new load that would not be able to connect if the Project did not receive leave to construct? If it does not, please update Table 1 of Reference 1 to accurately reflect incremental revenue to the network rate pool.

b) Which company generated the load forecast in Table 1 of Reference 1? What would be the consequences to the network rate pool if actual load turned out to be lower than this forecast?

c) According to Reference 1, the existing 115 kV H9A circuit is classified as a "multi-purpose (dual function line)" asset. According to Reference 2, the Hawthorne TS to Orleans TS line section of the existing H9A circuit is classified as a line connection. Please clarify the discrepancy.

d) According to Reference 1, neither the lines nor the stations component of the Project is attributable to any specific request by a customer. Please clarify whether Hydro Ottawa requested an increase in supply capacity between the 2020 IRRP and the 2023 Orleans Area Planning Study due to an increased load forecast. Please clarify whether the connection of the Mer Bleue MTS is possible without the Project. Please explain why the Project is not attributable to Hydro Ottawa.

e) Please identify the customers that are supplied or are to be supplied by each of Bilberry Creek TS, Mer Bleue MTS, and Orleans TS.

f) According to Reference 3, where a transmitter-owned connection facility has reached its end-of-life and is planned to be retired, and its replacement with a new connection facility is determined to be the optimal solution, the transmitter shall recover a capital contribution from a customer to replace the connection facility, where the customer requires additional capacity. Does this section of the TSC apply to the replacement of Bilberry Creek TS with Mer Bleue MTS and an upgraded Orleans TS? Please explain.

g) According to Reference 4, where a transmitter-owned connection facility has not reached its end-of-life and is replaced at the request of a customer, the transmitter shall recover a capital contribution from the customer. Does this section of the TSC apply to the replacement of the 115 kV equipment at Orleans TS with new 230 kV equipment? Please explain.

Response:

a) Yes. Table 1 in **Exhibit B, Tab 9, Schedule 1** includes the incremental load for the region as identified through the regional planning process, and in turn the anticipated incremental revenue to the rate pool.

b) As noted in the response to part a) above, the forecast used in the analysis, presented in **Exhibit B, Tab 9, Schedule 1** was developed as part of the regional planning process by the Greater Ottawa Regional Planning Technical Working group, which includes stakeholders from IESO, Hydro One and LDCs. Assuming all other load forecasts remain unchanged, if actual load for this region were to be lower than the forecast in this Application, the rate pool revenue would be lower than OEB-approved revenue during the applicable rate period; with rates subsequently reset in the following rate period. Notwithstanding any differences between forecast and actual load, the proposed infrastructure investments would remain necessary to ensure the area continues to be supplied in a reliable and effective manner.

c) Circuit H9A is used for both load supply and as an interconnection with Lievre Power in Quebec where power may be either imported or exported. Accordingly, as identified in the referenced EB-2021-0110 application, the various sections of circuit H9A are allocated to multiple functional categories, including Network, Line Connection, and Other. As such, the circuit H9A should be considered a “multi-purpose (dual function line)” asset.

d) As noted in the response to part b) above, the Project is undertaken as a recommendation of the Greater Ottawa Regional Planning Technical Working group and is intended to address multiple regional system needs, as outlined in **Exhibit B, Tab 3, Schedule 1** and further detailed in the 2026 RIP report and the IESO’s evidence provided in **Exhibit H, Tab 1, Schedule 1, Attachment 2** and **Exhibit B, Tab 3, Schedule 1, Attachment 1**, respectively. Accordingly, the Project was not requested by, nor is it attributable to, any one specific customer.

The connection of the Mer Bleue MTS to the existing system configuration via circuit D5A is not possible due to the load security requirements in the Ontario Resource and Transmission Assessment Criteria which specifies that the transmission system must be planned so that the total load interrupted does not exceed 150 MW for a single-element contingency. Given that there is already more than one station connected to circuit D5A, connection of additional stations would result in more than 150 MW loss by configuration.

As mentioned above, the Project is intended to address multiple regional system needs in accordance with the recommendations of the Greater Ottawa Regional Planning Technical Working group. Further, the IESO supports the Project as a necessary and timely development that complements broader regional planning efforts, aligns with provincial decarbonization goals, and ensures reliable electricity supply for the growing Orleans area and the Greater Ottawa Area, as stated in **Attachment 1 of Exhibit B, Tab 3, Schedule 1**.

e) Hydro Ottawa is currently supplied, or is expected to be supplied, from Bilberry Creek TS, Orleans TS and Mer Bleue MTS, whereas Hydro One Distribution is currently supplied, or is expected to be supplied, from Bilberry Creek TS and Orleans TS.

f) Section 6.7.2 of the Transmission System Code does not apply to the Project. As noted in the response to part d) above, it is not accurate to suggest that the decommissioning of Bilberry Creek TS is being retired and replaced with a new connection facility. The recommendation to not refurbish Bilberry Creek TS was made as part of a broader assessment of regional system assets (transmission, distribution, energy efficiency) and future regional system needs. The Project has multiple components (a new 230 kV termination point at Hawthorne TS, a new 115 kV transmission line that will not be connected to Orleans TS, and station modifications at both a network station and transformation connection station) but notably does not include the decommissioning of the Bilberry Creek TS (which is scheduled for 2030). While the load currently served by Bilberry Creek TS will need to be transferred partly to a new Hydro Ottawa's Mer Bleue MTS and partly to Hydro One's Orleans TS, it would be incorrect to view the decommissioning of Bilberry Creek TS as the driver of the station modifications at the Orleans TS that form part of the Project. Finally, the proposed Project has been confirmed by the Greater Ottawa Regional Planning Technical Working group and the IESO as the optimal solution for the region. Hence, there is no capital contribution required from a customer.

g) The new 230 kV assets to be installed at the Orleans TS are not driven by a customer request as stated in response to part d) above. Consequently, section 6.7.2A of the Transmission System Code does not apply~~.~~

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OEB STAFF INTERROGATORY - 10

Reference:

Ontario Energy Board Act, 1998, S.O. 1998, c. 15, Sched. B, s. 1(1)

Preamble:

One of the objectives of the OEB is to regulate the electricity sector in a manner that supports economic growth, consistent with the policies of the Government of Ontario.

Interrogatory:

a) Please explain if and how the Project would support economic growth in the province of Ontario.

Response:

a) The Project supports economic growth in a manner that is consistent with the policies of the Government of Ontario.

First, as outlined in **Exhibit B, Tab 3, Schedule 1**, the Project addresses a critical need to ensure sufficient 115 kV and 230 kV supply capacity to meet the growing electricity demand in the Orleans area. This demand growth is driven by long-term development and electrification trends, including population increases, new residential development, and expanded electrification in eastern Ontario. By increasing transmission capacity, the Project enables the continued economic development of the region, an objective that is precisely aligned with section 1(1)2.1 of the *OEB Act*. The need for the Project is documented in the regional planning reports included as attachments to **Exhibit H, Tab 1, Schedule 1**.

Second, the Project aligns with Ontario's key policy document related to the electricity sector – i.e., Ontario's Integrated Energy Plan[1], which emphasizes the importance of taking action to ensure that demand growth in eastern Ontario is not constrained by transmission capacity. Adequate and reliable electricity supply is necessary for economic growth and the changing needs of Ontario's economy. Businesses and residential developments require an electricity system with the capacity to serve them. By expanding the 230 kV system while preserving the 115 kV system in the Orleans area, the Project directly supports the Government of Ontario's policy objective of enabling economic growth through infrastructure investment. Further, as outlined in **Attachment 1 of Exhibit B, Tab 3, Schedule 1**, the IESO supports the Project as necessary to ensure reliable supply for the growing Orleans area.

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[1] Energy for Generations, Ontario's Integrated Plan to Power the Strongest Economy in the G7 (June 2025), p. 72.

Third, the Project will strengthen the transmission system and improve overall supply reliability by upgrading Orleans TS to a standard 230 kV DESN configuration. This will shift load from the constrained 115 kV system to the 230 kV system, improving operability and reliability in the Orleans area. Enhanced reliability reduces the risk of supply interruptions that result in significant costs for businesses and residents. The preservation of the existing 115 kV system will also enable efficient use of existing assets to support future growth in the Orleans area.

In summary, the Project supports and enables economic growth by ensuring that the electricity transmission system has adequate capacity and reliability to accommodate ongoing and future development in the Orleans area, consistent with the objectives of the OEB Act and the policies of the Government of Ontario.

OEB STAFF INTERROGATORY - 11

Reference:

1. Exhibit F-1-1, Page 1
2. Exhibit G-1-1, Page 1
3. Exhibit G-1-1, Attachment 1, Page 6
4. Exhibit H-1-1, Attachment 2, Page 62

Preamble:

According to Reference 1, Hydro One Networks expects to receive the IESO's final System Impact Assessment (SIA) shortly.

According to Reference 2, Hydro One Networks expects to finalize the Customer Impact Assessment (CIA) following the receipt of the IESO's final SIA and once all customer comments on the draft CIA have been addressed.

According to Reference 3 and Reference 4, "Orleans TS will no longer be subject to momentary interruptions due to its configuration" as a result of the Project.

Interrogatory:

a) Please provide the final SIA prepared by the IESO.

b) Please provide the final CIA.

c) Please elaborate on the momentary interruptions that result from the current configuration at Orleans TS and how the Project would improve reliability and quality of electricity service.

Response:

a) Please refer to Attachment 1 of this Schedule for a copy of the IESO's final SIA.

b) Please refer to Attachment 2 of this Schedule for a copy of the Hydro One's final CIA.

c) Under current configuration at Orleans TS, the station is connected to both the 230 kV circuit D5A and the 115 kV circuit H9A. However, due to the stations' non-standard configuration, the station is normally only supplied through one of these transmission circuits. As a result, any momentary fault on the circuit currently supplying the station, such as a lightning strike resulting in protection operation, will cause a momentary interruption at the station. Following the proposed upgrade to a standard DESN configuration with two 230 kV supply circuits in operation, a momentary fault on one supply circuit will not result in any interruption at the station, as the remaining supply circuit can supply the full station load.

Filed: 2026-08-25
EB-2026-0018
Exhibit I-1-11
Attachment 1
Page 1 of 17

System Impact Assessment Report

Final Report - Public

CAA ID: 2025-834
Project: Hawthorne x Orleans Transmission Reinforcement
Connection Applicant: HYDRO ONE NETWORKS INC.

July 8, 2026

ieso
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Powering Tomorrow.

Acknowledgement

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

Disclaimers

IESO

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

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

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

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

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

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

Hydro One

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

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

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

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

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

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

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Project Description

Hydro One Networks Inc. (the "connection applicant" and "transmitter") is planning the following changes to the IESO-Controlled Grid (the "project"):

- Build a new 11.3 km long 230 kV circuit A25, between Hawthorne Transformer Station (TS) and Orleans TS.
- Replace a 11.2 km section of the existing 115 kV circuit H9A, between Hawthorne TS and Orleans TS.
- Replace the existing 50/66.7/83.3 MVA 110/28 kV transformer T1 at Orleans TS with a new 75/100/125 MVA 230/27.6/27.6 kV transformer. Orleans TS transformer T1 will tap to the new 230 kV circuit A25.
- Install a new 230 kV circuit breaker KL25 at the Hawthorne TS
- Install three new 27.6 kV circuit breakers at Orleans TS.
- Transfer Bilberry TS existing load to the Mer Bleue MTS and Orleans TS.

The project is planned to be in-service by Q2 2029.

Notification of Conditional Approval

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

Assessment Findings

System studies were carried out to identify the impact of the project on loading of transmission facilities, system voltages, voltage stability, transient performance, load security, and restoration and to verify that the applicable reliability standards are met. The studied scenarios and main assumptions are available in Appendix D of this report. The detailed study results are available in Appendix E of this report. Based on the assessment results, we have identified the following findings.

1. Under planning events where both KL25 and DL42 230 kV circuit breakers are open, the new transmission line A25 will become radially connected to 230 kV circuit A42T. This configuration can result in reverse active power flow through transformer T1 at Orleans TS and significantly reduce the short circuit level at Outaouais TS, potentially leading to unstable operation of the Ontario – Quebec high-voltage direct current (HVdc) interconnection facilities.
2. The Project will change one of Orleans TS tapped circuits from 115 kV circuit H9A to the new 230 kV circuit A25. Accordingly, the Under Voltage Load Shedding (UVLS) and shunt capacitor automatic switching settings shall be updated.

IESO Requirements for Connection

Specific Requirements:

The following specific requirements are applicable for the incorporation of the project and its connection facilities. Specific requirements pertain to the level of reactive power compensation needed, operation restrictions, special protection system, upgrading of equipment and any project specific items not covered in the general requirements.

Requirements for the Connection Applicant and the transmitter

1. To address finding #1, the connection applicant (the "transmitter") shall implement a cross-tripping scheme to trip breaker KL42 (L25L42) at Hawthorne TS and the 230 kV breaker of transformer T2 at Mer Bleue MTS when both the KL25 and DL42 breakers at Hawthorne TS are open.

   The scheme must have 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.

   During the IESO Market Registration process, a Facility Description Document (FDD) for the scheme must be provided and finalized at least nine months prior to the in-service date. The FDD must contain the finalized scheme as well as expected operating times.

2. To address finding #2, the connection applicant (the "transmitter") shall revise UVLS and shunt capacitor auto switching settings at Orleans TS. The UVLS shall operate if the voltage at any of the 230 kV buses drops below 205 kV for 1.5 seconds. Orleans TS shunt capacitor SC1 shall be automatically switched on when the voltage at any of the 230 kV buses drops below 220 kV for 5 seconds, and shall be switched off when the voltage at any of the 230 kV buses exceeds 250 kV for 5 seconds.

   During the IESO Market Registration process, a revised Facility Description Document (FDD) for Ottawa area UVLS (FDD-1029) must be provided and finalized at least nine months prior to the in-service date. The FDD must contain the finalized scheme as well as expected operating times.

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.

Recommendation

1. Power transformers with a high side, wye grounded winding with terminal voltage greater than 200 kV are subject to North American Electric Reliability Corporation (NERC) standard TPL-007, Transmission System Planned Performance for Geomagnetic Disturbance Events. As per NERC

standard TPL-007, the Planning Coordinator in conjunction with its Transmission Planner are required to implement a process(es) to obtain Geomagnetic Disturbance (GMD) measurement data, via geomagnetically-induced currents (GIC) monitors, which will aid in model validation and situational awareness. This data will more accurately support the owner of the applicable power transformer(s) to conduct a thermal impact assessment if required in the future. As such, it is recommended that the connection applicant makes provision(s) to install monitoring equipment for GIC on the new transformer(s).

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 are 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, 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 load facility has the capability to operate continuously between 59.4 Hz and 60.6 Hz and remain operational for a limited time beyond this range, in alignment with IESO, NERC, and NPCC frequency ride-through requirements for generators.

   The IESO may require changes to frequency ride-through settings based on updates in NERC or Market Rules requirements. Changes to these settings shall not be enabled without IESO approval.

4. In accordance with Appendix 4.3 of the Market Rules, the connection applicant shall ensure the project has the capability to ride-through routine switching events and design criteria contingencies on the transmission system assuming standard fault detection, auxiliary relaying, communication, and rated breaker interrupting times, unless disconnection by configuration or a lower level ride-through capability has been approved by the IESO.

   The connection applicant shall ensure that the project's equipment can operate continuously within the voltage requirements specified in section 2.4.2 and section 2.4.3 of the Ontario

Resource and Transmission Assessment Criteria (ORTAC) and remain operational for no less than 5 seconds beyond ORTAC post-contingency voltage limits.

The connection applicant will be required to demonstrate the project's voltage ride-through capability during commissioning by either providing manufacturer test results or monitoring several variables under a set of IESO specified field tests, and the test results must be verifiable using the dynamic models provided for the project.

The connection applicant will be required to take corrective actions that could include upgrades to the project, if the performance of their facilities becomes inadequate or causes any adverse impact on the IESO-controlled grid (e.g. tripping for out of zone faults) after the project is in-service. If upgrades are needed, the IESO may direct the transmitter or the distributor to disconnect the project until such upgrades are deployed, to the satisfaction of the IESO. Automatic reconnection of the loads to the system is not allowed.

The IESO may require changes to voltage ride-through settings based on updates in NERC or Market Rules requirements. Changes to these settings shall not be enabled without IESO approval.

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

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

   The connection applicant shall ensure that the circuit breakers 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 2.4.2 and Section 2.4.3 of ORTAC.

6. 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 2.4.2 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.

7. The connection applicant has a total peak load at all its owned facilities, including the project, which is greater than 25 MW. According to Section 10.4.6 of Chapter 5 of the Market Rules and Section 11.3 of the Market Manual 7.1, the connection applicant is required to participate in the automatic Under-Frequency Load Shedding (UFLS) program and must select 35% of total peak load among its owned facilities for under-frequency tripping, based on a date and time specified by the IESO that approximates system peak, according to Section 10.4 of Chapter 5 of the Market Rules.

   The UFLS relay connected loads shall be set to achieve the amounts to be shed as stated in Section 11.3 of Market Manual 7.1. Table 1: UFLS Relay Settings summarizes UFLS relay settings as a function of the total peak load of all facilities, including the project, owned by the connection applicant.

Table 1: UFLS Relay Settings

Aggregate Summer Peak Load	UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)	Load Shed at stage as % of Connection Applicant's Load	Cumulative Load Shed at stage as % of Connection Applicant's Load
25 MW or more and less than 50 MW	1	59.5	0.3	≥ 35	≥ 35
50 MW or more and less than 100 MW	1	59.5	0.3	≥ 17	≥ 17
	2	59.1	0.3	≥ 18	≥ 35
100 MW or greater	1	59.5	0.3	7 – 9	7 – 9
	2	59.3	0.3	7 – 9	15 – 17
	3	59.1	0.3	7 – 9	23 – 25
	4	58.9	0.3	7 - 9	32 - 34
	Anti-Stall	59.5	10.0	3 – 4	35 - 37

The connection applicant, in conjunction with the transmitter, must also ensure that capacitor banks connected to the same station bus as the load are shed by UFLS facilities at 59.5 Hz with a time delay of 3 seconds.

The maximum load that can be connected to any single UFLS relay is 150 MW to ensure that the inadvertent operation of a single under-frequency relay during the transient period following a system disturbance does not lead to further system instability.

The IESO will review the requirements annually and inform the relevant market participants of their automatic UFLS obligations.

8. 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.

9. The connection applicant shall ensure that the telemetry requirements for the project are satisfied as per the applicable Market Rules requirements. The finalization of telemetry quantities and telemetry testing will be conducted during the IESO's Market Registration process.

10. 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. Additional telemetry quantities may be applicable. 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.

11. The connection applicant must initiate the IESO's Market Registration process at least eight months prior to the commencement of any project related outages.

    The connection applicant is required to provide "as-built" equipment data for the project during the IESO Market Registration process. If the submitted equipment data differ materially from the ones used in this assessment, then further analysis of the project may need to be done by the IESO before final approval to connect is granted.

    As part of the IESO Market Registration process, the connection applicant must also provide evidence to the IESO confirming that the project's equipment installed meets the Market Rules requirements and matches or exceeds the performance predicted in this assessment. This evidence shall be either type tests done in a controlled environment or commissioning tests done on-site. In either case, the testing must be done not only in accordance with widely recognized standards, but also to the satisfaction of the IESO. Until this evidence is provided and found acceptable to the IESO, the Market Registration process will not be considered complete and the connection applicant must accept any restrictions the IESO may impose upon this project's participation in the IESO-administered markets or connection to the IESO-controlled grid. The evidence must be supplied to the IESO within 30 days after completion of commissioning tests. Failure to provide evidence may result in disconnection from the IESO-controlled grid.

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

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

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

Be advised that any registration changes could have an impact on a market participant's monthly global adjustment charges. Such registration changes include but are not limited to:

- New facility registrations
- Modifications to existing facility registration
- Electrical configuration changes
- Meter installation reconfigurations
- Full or partial transfers of a facility to a separate legal entity
- Transferring a facility between the retail electricity market and the IESO-administered wholesale electricity market (IAM)

Note that any newly registered facility in the IAM will automatically be treated as a Class B facility, unless stated otherwise in Ontario Regulation 429/04. It is the sole responsibility of the market participant to declare if any such provisions of Ontario Regulation 429/04 are applicable.

Subject to compliance with all regulatory requirements, a new facility may become eligible to participate in the Industrial Conservation Initiative (ICI) program (i.e. to be treated as a Class A facility) after the facility has been registered in the IAM for the entire duration of a base period (i.e. the facility has registered withdrawals from the IESO-controlled grid from May 1 to April 30 of the following calendar year).

12. The connection applicant shall ensure the wholesale metering installations comply with (i) the Ontario Market Rules, e.g., Chapter 6 - Wholesale Metering, Chapter 6 - Appendices, Chapter 9 - Settlements and Billing, Chapter 9 - Appendices, Chapter 10-Transmssion Service and Planning, (ii) the applicable market manuals, e.g., Market Manual 3 Series: Metering, and (iii) IESO wholesale metering hardware standards and policies. The connection applicant is encouraged to

seek advice from a metering service provider (MSP) or from the IESO in early stages of the project design.

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

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

Appendix B: Project Data (Confidential)

Appendix C: Facility Classification (Confidential)

Appendix D: Study Scope of Work (Confidential)

Appendix E: Detailed Study Results (Confidential)

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Powering Tomorrow.

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CUSTOMER IMPACT ASSESSMENT

HAWTHORNE X ORLEANS TRANSMISSION REINFORCEMENT

CIA ID: 2026-27
Revision: Final
Date: 20 August 2026

Issued by**:**
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Hydro One Networks Inc.

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Fred Kouhdani
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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) 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.

TABLE OF CONTENT

Customer Impact Assessment

Hawthorne x Orleans Transmission Reinforcement

1.0 Introduction

1.1 Purpose

Hydro One is proposing modifying the existing supply to the Orleans area by adding a new 230kV circuit and upgrading Orleans TS. The project is a recommendation of the Greater Ottawa Technical Working Group (TWG).

This Customer Impact Assessment (CIA) study assesses the potential impact of the new 230kV circuit on the transmission connected customer of 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 Customer Impact Assessment ("CIA") study to assess the potential impact of the proposed project on existing transmission customers in the affected area. As part of the Connection Assessment and Approval ("CAA") process, impact of the project 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").

This CIA study is intended to supplement the SIA report CAA ID 2025-834, dated 8 July 2026, which assessed the Hawthorne x Orleans Transmission Reinforcement project and concluded that there is no adverse impact of this proposed project on the transmission system.

This is the final CIA study report for this project, no comments were received by affected customers.

1.2 Background

The Orleans area is supplied by two 115kV circuits (A2 and H9A), and one 230kV circuit (D5A). Circuits D5A and H9A are on the same towers and are in the southern part of the area, whereas circuit A2 is a single tower circuit and on the northern part of the area. The two main stations supplying the area are Bilberry Creek TS which is supplied by A2 and H9A, and Orleans TS which is supplied by 230kV D5A and 115kV H9A.

In the 2020 Regional Planning for the Greater Ottawa region, the Orleans area was reviewed, and it was determined that the existing system configuration was adequate to meet the expected demand using the existing 115kV and 230kV stations. However, as further information became available after the publication of the reports in 2022/23, the Technical Working Group further reviewed the area while the Regional Planning process was inactive for the region. A new plan that would modify the area supply was agreed as the preferred option and was thus recommended by the TWG.

The recommendation made by the TWG is to provide a new 230kV circuit to the area, upgrade Orleans TS to a 230kV DESN station, and build a new 230kV Hydro Ottawa Municipal Transformer Station. This plan will also allow the retirement of 115kV station Bilberry Creek TS which is due for significant sustainment work, including the replacement of both step-down transformers.

This project will address the new 230kV circuit and upgrades at Orleans TS. To provide the new 230kV circuit, Hydro One is planning to make use of the existing H9A conductors on the D5A/H9A towers. These conductors are built for 230kV; however, they operate at 115kV to supply the existing 115kV distribution stations connected to the line. This project will thus connect the H9A conductors at 230kV at Hawthorne TS, and this new 230kV circuit will be labeled A25. To replace the conductors of 115kV circuit H9A, the project will build a 115kV circuit on the existing right of way, between the D5A/H9A towers and A41T/A42T towers, please refer to Figure 1. At Orleans TS, the existing 115kV/27.6kV transformer will be replaced with a 230kV/27.6kV/27.6kV transformer, and this new transformer will be connected to circuit A25, please refer to Figure 2.

This plan addresses several needs for the region and provides the following benefits:

- Address the limited growth available on the 115kV due to the 230kV/115kV 250MVA autotransformer loading at Hawthorne TS and Merivale TS. By moving load from the 115kV to the 230kV system, the autotransformer loading is reduced which will help supplying growth at existing 115kV stations which cannot be easily upgraded to 230kV.
- Avoid significant refurbishment work at Bilberry Creek TS, allowing the station to be retired and its load supplied from 230kV. In addition, Bilberry Creek TS has limited growth even if the station is refurbished.
- Orleans TS will no longer be subject to momentary interruptions due to its configuration.
- Allow more growth in the Orleans area with the addition of a new 230kV circuit.

1.3 Connected Customers

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 of the project. Hydro Ottawa Limited and Hydro One Distribution are the two transmission connected customers in the electrical vicinity[1].

Station	Customers
Orleans TS	Hydro One Distribution Hydro Ottawa

[1]Only Orleans TS configuration changes as a result of the new circuit. There are several distribution stations connected to 115kV cuircuit H9A, however no impacts are expected at any of these stations and thus they are not listed.

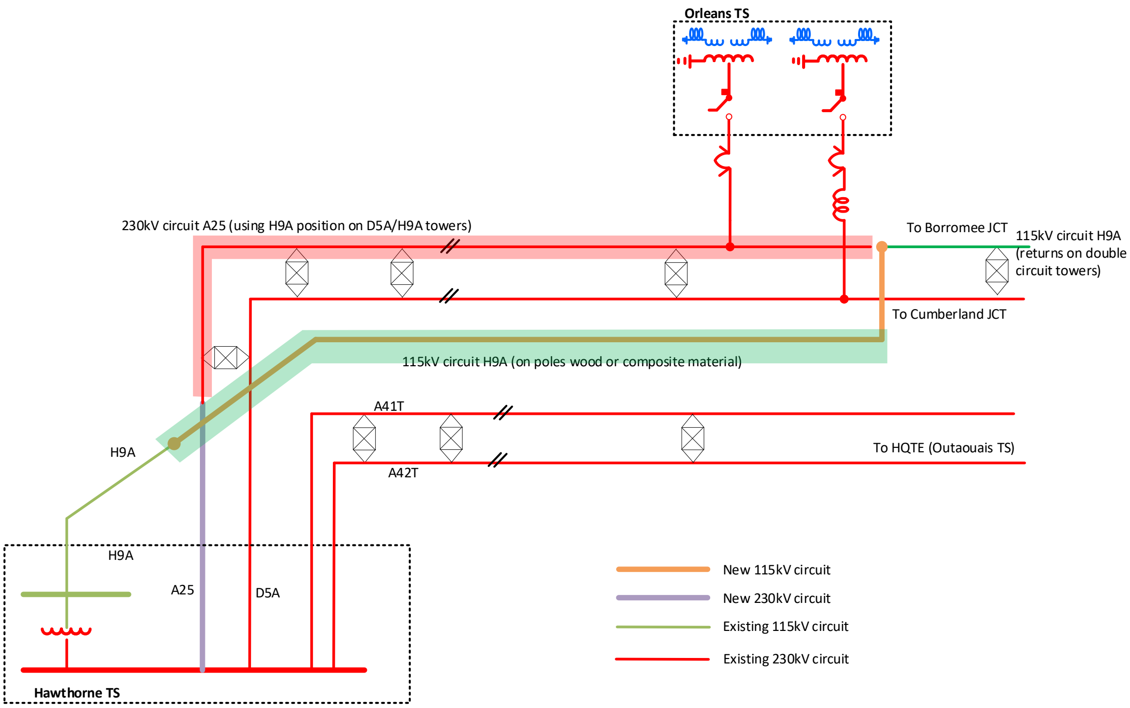

Figure 1.SLD of Hawthorne TS to Orleans TS corridor.

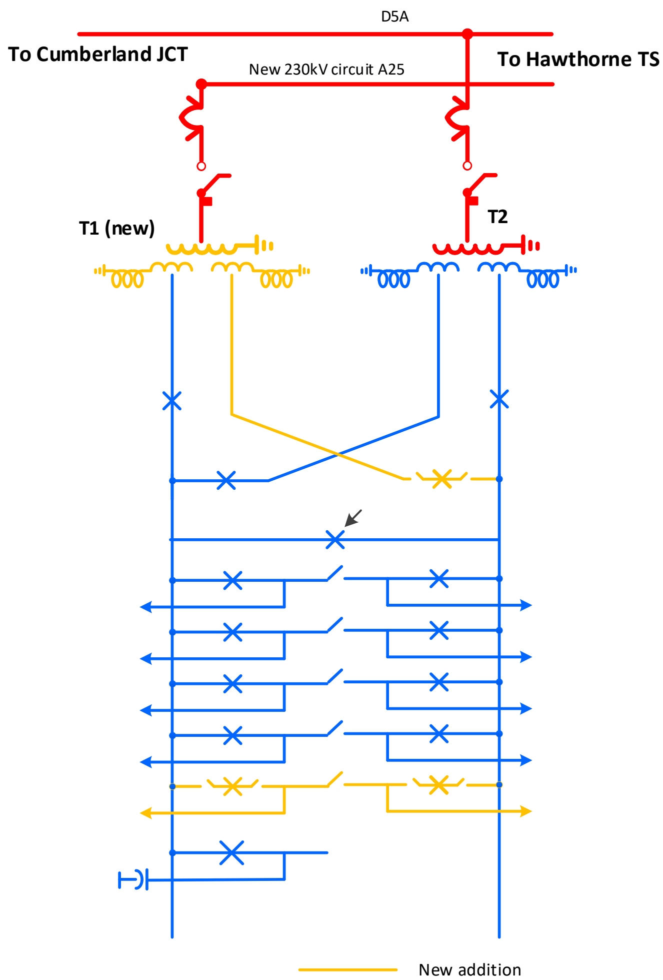

Figure 2. Orleans TS 230kV DESN.

2.0 LOAD FLOW

The SIA completed by IESO found that the Hawthorne x Orleans upgrade project has no negative impact on the transmission system. Please refer to IESO document CAA ID 2025-834.

The CIA also assessed the area system performance following the completion of the Hawthorne x Orleans for the base case (with all facilities in service) and for one element out of service. All bus voltages are within criteria, and no voltage violations were found for these conditions.

3.0 SHORT- CIRCUIT STUDY

The fault levels for the station of the area are not expected to have any impact as a result of the new 230kV circuit.

The upgrade at Orleans TS will cause an increase in short circuit level at the 27.6kV bus when compared to the existing system, where the station is supplied from the 115kV. This is due to the configuration of Orleans TS, when the station is supplied by the 115kV, only one transformer winding supplies the 27.6kV bus. With the new configuration, each 27.6kV bus will be supplied by two transformer windings, thus increasing the fault level. However, the increase is within the TSC and equipment rating.

4.0 CUSTOMER RELIABILITY

The project is not expected to have a negative impact on the customers of the area. In fact, this project will improve supply reliability to customers supplied by Orleans TS. In addition, the project will also allow for growth in the Orleans area.

5.0 CONCLUSION

This CIA study has reviewed the impact of the Hawthorne x Orleans project on the existing transmission customers connected in the Orleans area. The project is not expected to have any negative effect on the voltages and supply reliability of customers in the area.

Fault levels at buses are in accordance within the Transmission System Code requirement and equipment specifications.

All customers are requested to review the fault levels provided in Appendix A to ensure that the capability of their equipment and grounding system is not exceeded.

6.0 APPENDIX A

Short circuit level before and after the project is complete.

		Before project				After project				Breaker ratings	
		Sym		Asym		Sym		Asym		Sym	Asym
Station Bus	Voltage	3ph	LG	3ph	LG	3ph	LG	3ph	LG	3ph/LG	3ph/LG
Orleans D5A	250	13.7	12.6	15.1	13.3	13.8	12.7	15.4	13.6	-	-
Orleans A25	250	n/a	n/a	n/a	n/a	12.4	11.4	13.9	12.2	-	-
Orleans J bus	29	12.2	9.8	15.5	12.9	13.5	10.4	16.9	13.4	31.5	37.8
Orleans Q bus	29	7.0	5.3	8.8	6.9	13.2	10.2	16.4	13.2	31.5	37.8

Please note: the short circuit result shown for Orleans Q bus before the project represents the value when the station is supplied from the 115kV system; the J bus value represents the value when the station is supplied from the 230kV.

OEB STAFF INTERROGATORY - 12

Reference:

1. Exhibit E-1-1
2. July 13, 2026 Letter of Comment from National Capital Commission

Preamble:

According to Reference 2, the National Capital Commission (NCC) is seeking to negotiate 49-year fixed term easements with Hydro One Networks.

Interrogatory:

a) Reference 1 does not reference 49-year fixed term easements. Please provide the latest version of the land use agreements proposed to be offered by Hydro One Networks.

Response:

a) The sale or transfer of federally owned land in the National Capital Region requires approval from the National Capital Commission (NCC) and is subject to the Federal Land Use, Design, and Transaction (FLUDTA) process. Hydro One has applied to the NCC for the issuance of the FLUDTA to enable Hydro One to construct the Project over federal lands. The NCC and Hydro One continue to work collaboratively towards securing the necessary for FLUDTA approval.

Once Hydro One receives FLUDTA approval, Hydro One and the NCC will be in a position to transact on the new easements that are required for the Project. The NCC is governed by the *National Capital Act* and must follow its policies and procedures. Accordingly, the NCC will utilize its own forms of agreements, which are subject to 49 year fixed-term easements, rather than the forms of agreements filed as attachments to **Exhibit E, Tab 1, Schedule 1**. Hydro One notes that similar agreements with the NCC have been entered into for the Power South Nepean Project (EB-2019-0077).

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OEB STAFF INTERROGATORY - 13

Reference:

1. Exhibit B-3-1, Attachment 1, Pages 3-5
2. 2022 Needs Assessment – Greater Ottawa, Page 16

Preamble:

In addition to Question c) of Staff – 4, one additional clarification is requested.

Interrogatory:

a) Is the Ottawa 115 kV System Supply Study mentioned in Reference 2 the same document as the 2023 Orleans Area Planning Study mentioned in Reference 1? If it is not, please provide the Ottawa 115 kV System Supply Study mentioned in Reference 2.

Response:

a) As noted in Section 4.3 of the 2023 Orleans Area Planning Study, provided in response to part c) of **Exhibit I, Tab I, Schedule 4**, the IESO initiated a study of the Ottawa 115 kV System in 2021 following a recommendation arising from the 2020 IRRP. The study was not completed as a standalone study due to the advancement of the next cycle of the IRRP in March 2023. The underlying needs and considerations associated with the Ottawa 115 kV system were subsequently evaluated through the regional planning process and informed the development of the 2025 IRRP, provided as **Attachment 1 of Exhibit H, Tab 1, Schedule 1**.

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