Renfrew

REGIONAL INFRASTRUCTURE PLAN

July 13, 2023

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Ottawa River Power Corporation (ORPC)

Disclaimer

This Regional Infrastructure Plan (RIP) Report for Renfrew region was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Technical Working Group.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE TECHNICAL WORKING GROUP IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE RENFREW REGION.

The participants of the Renfrew Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process. Hydro One, as the lead transmitter undertakes the development of a RIP with input from the Technical Working Group (TWG) for the region and publishes a RIP report. The second cycle of the Regional Planning process for the Renfrew region was initiated with Needs Assessment (NA) and the report was published in May 2021 by Hydro One. This was followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) which were published in August 2021 and December 2022, respectively, by the Independent Electricity System Operator (IESO).

The Renfrew RIP provides a consolidated summary of needs and recommended plans for the region over a study period of 2022-2042 based on available information. In this regional planning cycle, plans are recommended for the near to medium-term needs. The needs for the longer term were assessed but due to uncertainties in the load growth, long-term needs will be monitored and further reviewed in next regional planning cycle.

I. **Following Major projects were completed during the last ten years:**
   - Chenaux TS: 230/115 kV, T3 & T4 Autotransformers replaced with new 75/100/125 MVA units along with regulators TR3 and TR4, 115kV oil circuit breakers 4X6 and 4X2Y, completed in 2021.

II. **Following Major projects are underway:**
   - 115kV D6 Circuit: Complete line refurbishment of 76.8 km Line section between Des Joachims TS and Petawawa/Craig DS, planned in-service date in 2025.

III. **New needs identified during the second cycle regional planning:**

   a. **Asset Renewal for Major HV Transmission Equipment**

- No new major HV Transmission Asset renewal identified.

b. Station Capacity

- Pembroke TS: Currently exceeding summer station LTR.
- Forest Lea DS: Currently exceeding summer station LTR.
- Petawawa DS: Update on need as identified in IRRP.

c. Transmission Line Capacity

- No new Transmission Line capacity identified.

d. System Reliability, Operation and Load restoration

- No System Reliability, Operation and Load restoration issues identified.

e. Long term needs

- Des Joachims sub-system supply capacity: Monitor load growth in the area.

The major infrastructure investments in this second cycle recommended by the TWG in the Renfrew Region over the near, medium and long-term period are given in Table 1 below, along with their planned in-service date and estimate for planning purposes.

Table 1. Renfrew Region - Recommended Plans over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE RENFREW REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Ottawa River Power Corporation (ORPC)

The Renfrew region is located in Eastern Ontario with the majority of load along the Ottawa river. For electrical planning purposes this region includes eighteen municipalities including the towns of Arnprior, Deep River, Laurentian Hills, Petawawa and Renfrew. As well as the townships of Admaston/Bromley, Bonnechere Valley, Brudenell, Lyndoch and Raglan, Greater Madawaska, Head, Clara and Maria, Horton, Killaloe, Hagarty and Richards, Laurentian Valley, Madawaska Valley, McNab/Braeside, North Algona Wilberforce and Whitewater Region; as well as the City of Pembroke. Figure 1-1 represents the Renfrew Region Map.

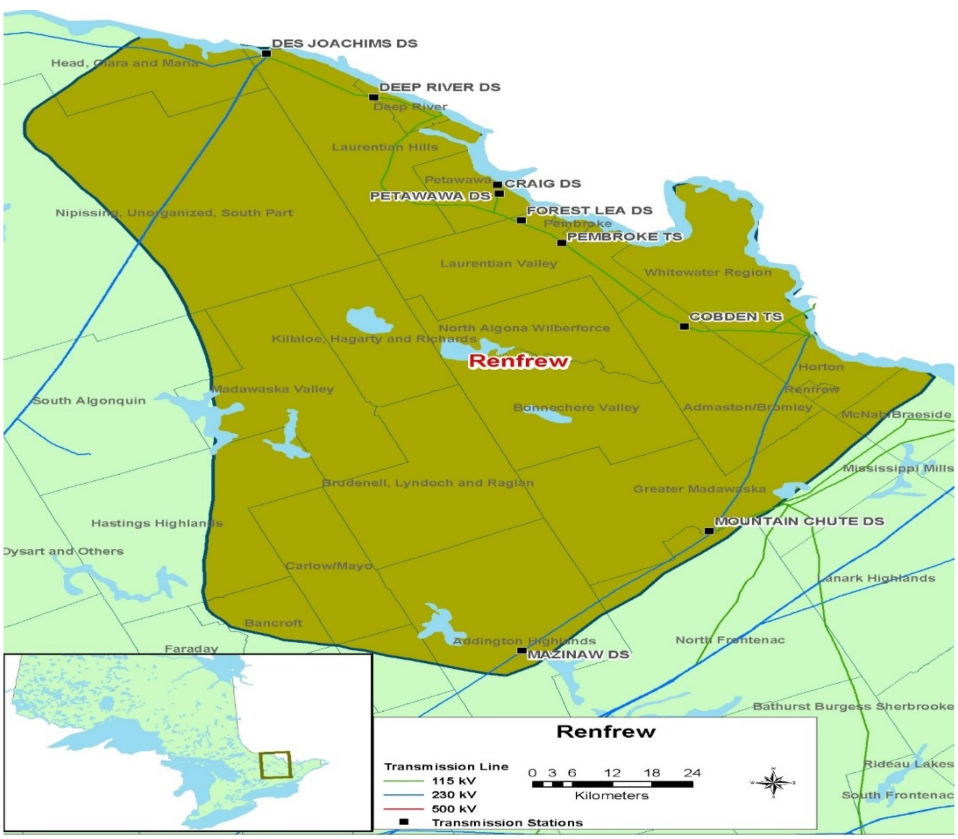

Figure 1-1 Renfrew Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the Renfrew Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region;
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the needs and relevant wires plans to address near, and medium-term needs identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the study period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the Renfrew IRRP or identified by the TWG.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs.
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Technical Working Group (TWG) assess, and document which of the needs that,

a. can be addressed directly between the customer and transmitter along with a recommended plan, and;
b. require further regional coordination and identification of LDCs to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the TWG as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs,

a. are local in nature,
b. require limited investments in wires (transmission or distribution) solutions, and;
c. do not require upstream transmission investments.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region were identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options which the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders and establishes a Local Advisory Committee (LAC) in the region or sub-region.
The RIP phase is the final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter to the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- Planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2 -1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

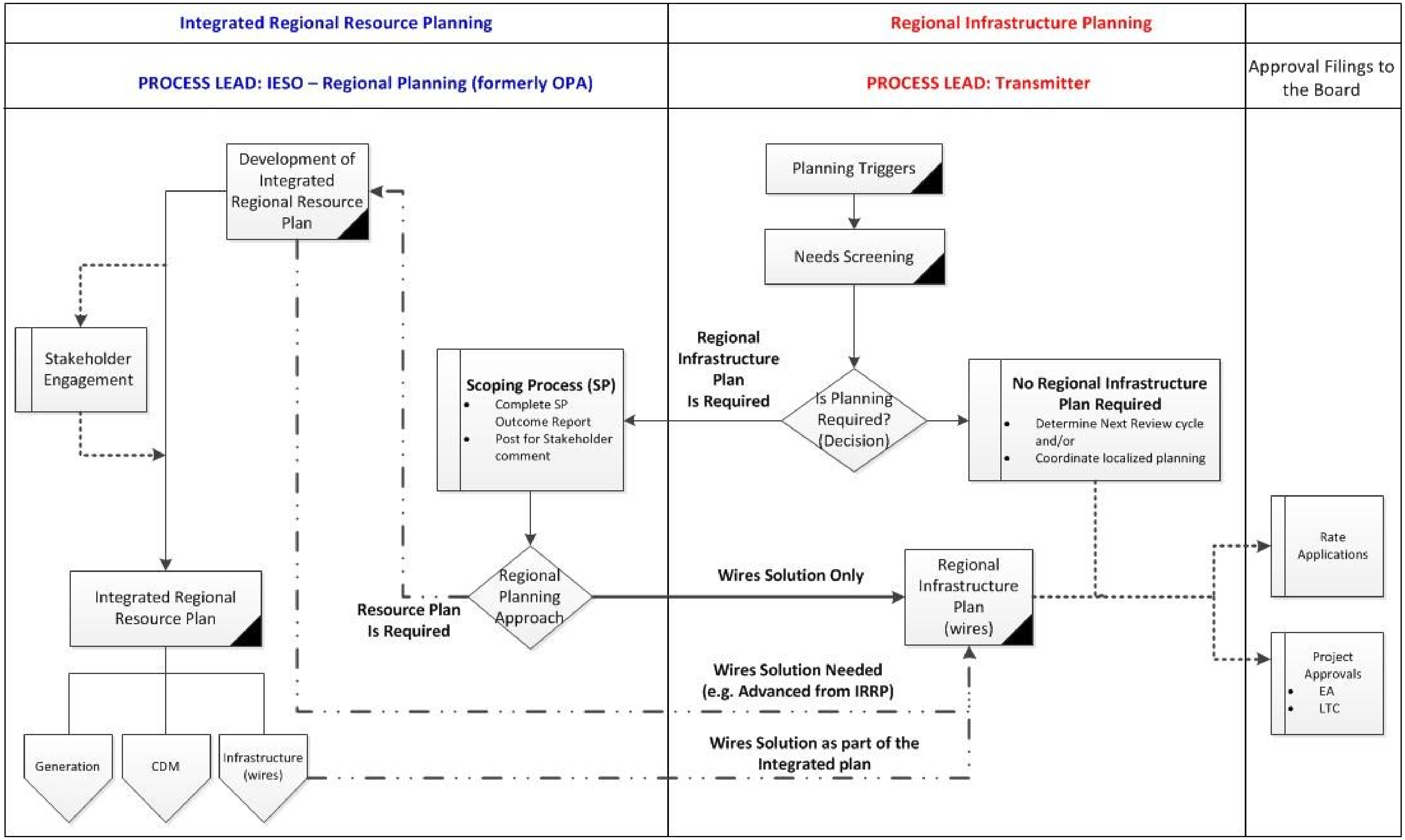

Figure 2-1 Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four-step process (see **Error! Reference source not found.**) as follows:

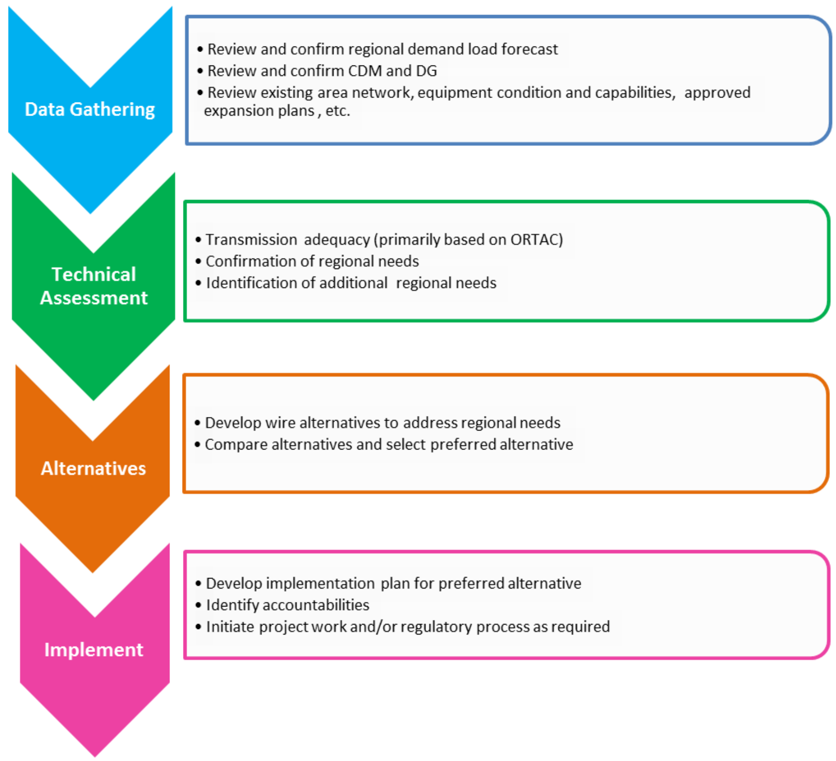

Figure 2-2 RIP Methodology

1. Data Gathering: The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) to reconfirm or update the information as required. The data collected includes:

   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs. As agreed by TWG members, the load forecast from the IRRP was adopted for this RIP, with the exception of Petawawa DS.
   - Review and confirm electrification, other growth scenarios, etc. which effects the projects recommended in in previous stages.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

3. REGIONAL CHARACTERISTICS

THE RENFREW REGION IS LOCATED IN EASTERN ONTARIO WITH THE MAJORITY OF LOAD ALONG THE OTTAWA RIVER. THE ELECTRICITY SUPPLY TO THE REGION IS PROVIDED THROUGH ONE 230KV CIRCUIT X1P AND THREE 115 KV RADIAL CIRCUITS: D6, X6 AND X2Y. THE 115KV CIRCUITS ARE SUPPLIED BY 230/115 KV AUTOTRANSFORMERS AT CHENAUX TRANSFORMER STATION (TS) FROM THE EAST AND DES JOACHIMS TS FROM THE WEST. A NORMALLY OPENED 115KV SWITCH AT PEMBROKE TS ISOLATES THE EAST AND THE WEST SIDES OF THE REGION.

The Renfrew region is bounded by the Des Joachims TS on the West and Chenaux TS on the East, and 230kV circuit X1P to the South. The distribution system in this region consists of voltage levels 44 kV and 12.5 kV. The main generation facilities in the Renfrew region are Chenaux Generation Station (GS) of 143.7 MW, Mountain Chute GS of 170.2 MW and Des Joachims GS of 432.5 MW

Hydro One Networks Inc. (Distribution) is the main LDC in the area. Other LDCs supplied from electrical facilities in the Renfrew region include Ottawa River Power Corporation and Renfrew Hydro Inc., both are embedded into Hydro One's distribution system. Renfrew Hydro Inc. customers are being fed from Stewartville TS which is part of the Greater Ottawa Regional Planning. As such, Renfrew Hydro Inc. has not been included as part of this NA.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1.

- Chenaux TS is a major 230kV station in the region. The station has 143.7MW of hydraulic generation connected to the 230kV bus. The station connects to the bulk system via a single 230kV circuit X1P. Two autotransformers step down the voltage to 115kV to supply two radial circuits X6 and X2Y
- The 115kV circuits X6 and X2Y from Chenaux TS supply four stations: Pembroke TS, Cobden TS, Cobden DS and Customer Transformer Station (CTS-1).
- Des Joachim TS is the other major 230kV transformer station in the Region. There are 432.5MW of hydraulic generation connecting to the 230kV bus. The station interconnects to the Bulk Electric System (BES) via five 230kV circuits which are not in the scope of this regional assessment. Two autotransformers (one operates as standby) step down the voltage to 115kV to supply one radial circuit D6.
- The 115kV circuit D6 from Des Joachim TS 115kV bus supplies six stations: Des Joachims Distribution Station (DS), Deep River DS, Craig DS, Forest Lea DS, Petawawa DS, and Customer Transformer Station (CTS-2)
- Bryson GS from Hydro Quebec can be radially connected to Renfrew region via X2Y, when required.
- The 230kV single circuit X1P from Dobbin TS to Chenaux TS connects two stations in Renfrew region: Mountain Chute GS (with hydraulic generation of 170.2MW) and Mazinaw DS.

- Mountain Chute DS, a 115kV station adjacent to Mountain Chute GS, is supplied by a circuit W3B from outside of the studied region.

The circuits and stations of the area are summarized in the Table 2-1 below:

Table 1-1: Transformer Station and Circuits in the Renfrew region

115kV circuits	230kV circuits	Transformer Stations	Generation Stations
D6, X6 and X2Y	X1P	Des Joachims TS*, Des Joachims DS, CTS-1, Deep River DS, Chalk Craig DS, Petawawa DS, Forest Lea DS, Pembroke TS, Cobden TS, Cobden DS, CTS-2, Chenaux TS*, Mountain Chute DS and Mazinaw DS.	Mountain Chute GS (170.2MW) Des Joachims GS (432.5MW) Chenaux GS (143.7MW)

*Stations with Autotransformers installed

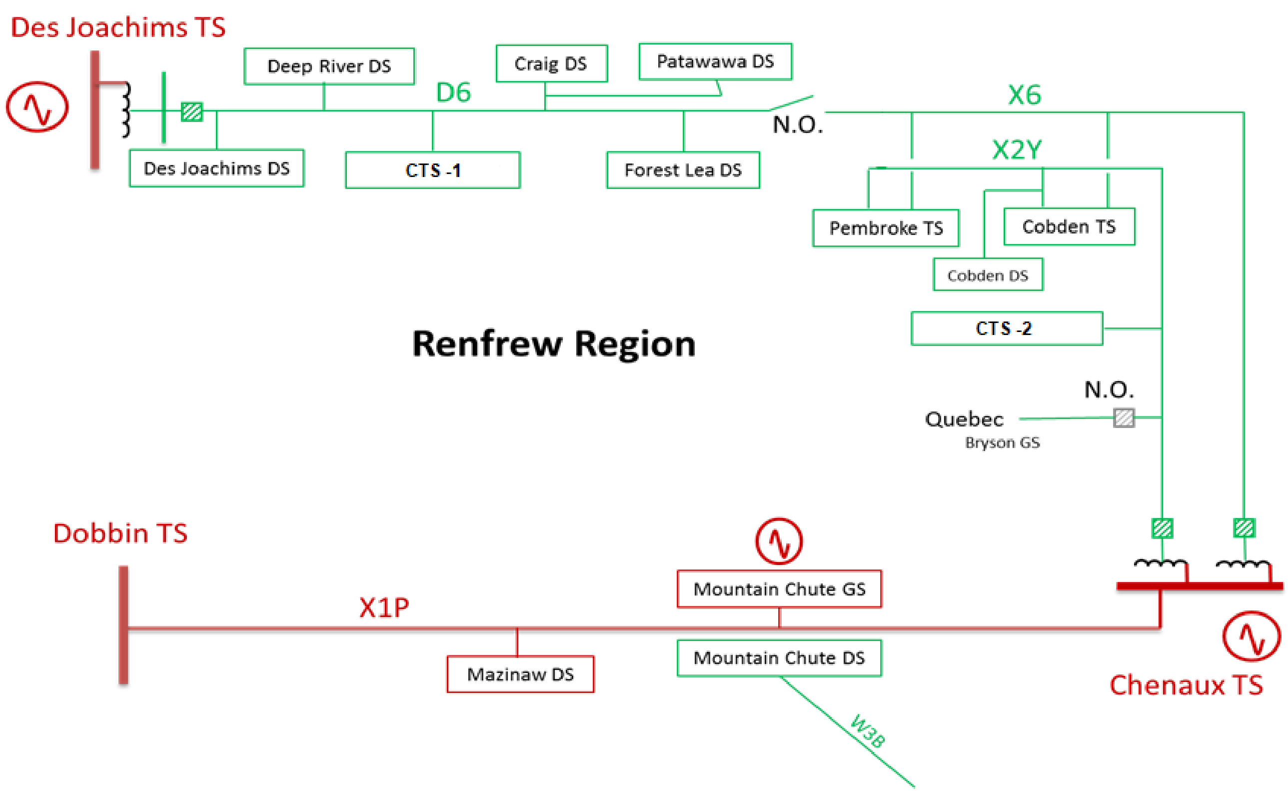

Figure 3-1 Renfrew Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE RENFREW REGION.

A list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub-sections. As a part of this or previous Regional Planning Cycle(s), several "Major HV Transmission Projects" were recommended in the Renfrew region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner(TAO) in the region, has undertaken the execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

1. Chenaux TS Autotransformer Replacement (2021): The 230/115 kV T3/T4 Autotransformers were replaced by new 75/100/125 MVA units along with associated facilities.

II. Following Major projects are underway:

1. 115kV D6 Line refurbishment (2025): This project is currently underway and includes complete refurbishment of 76.8km line between Des Joachims TS and Petawawa/Craig DS due to its condition assessment.

Note: The planned in-service year for the above projects is tentative and is subject to change.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The TWG adopted the IRRP load forecasts for this RIP as no material change was identified, with the exception of Petawawa DS. At Petawawa DS, the load increased abnormally in June 2020 due to generator refurbishment work at a customer facility connected to Petawawa DS which resulted in adding about 3.1 MW to station peak. The load returned to its normal value after the work was completed in July 2020. The updated load forecast for Petawawa DS considers the updated actual peak load recorded in 2021.

The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast. The municipalities were contacted as part of IRRP stakeholder engagement process to get their insight on the future load growth and was considered during IRRP load forecast development. During the study period, the load in the Renfrew region is expected to grow at an average annual rate of approximately 1.5% in summer from 2022 to 2042. The assessment is based on both summer and winter peak loads.

Figure-5-1 & 5-2 shows the Renfrew region extreme summer & winter weather non-coincident load forecast from 2022 to 2042. The load forecast from the Renfrew region IRRP was adopted as agreed to by the TWG, except for Petawawa DS. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident forecast for the individual stations in the region is available in Appendix E and is used to determine any need for station capacity relief in the region.

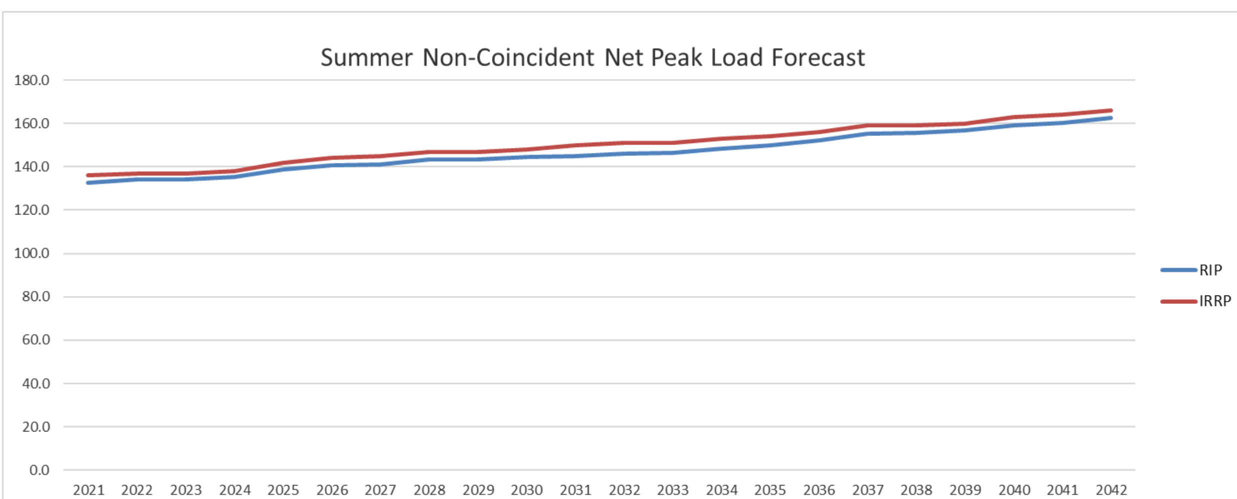

Figure 5-1 Renfrew Region Non–Coincident Net Summer Peak Load Forecast

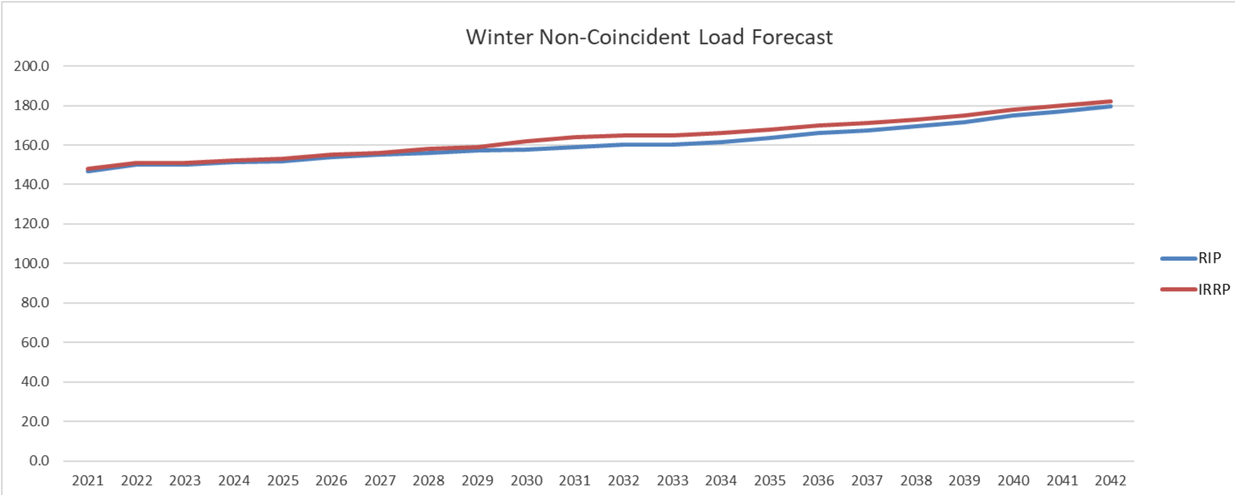

Figure 5-2 Renfrew Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2042.
- LDCs reconfirmed load forecasts up to 2042 in the area are the same as the IRRP(except for Petawawa DS).
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is summer peaking, so this assessment is based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR) based on 35°C ambient temperature.
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE RENFREW REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- Renfrew region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- Renfrew region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- Renfrew region Second cycle Integrated Regional Resource Plan Report, Completed in December 2022 by the IESO

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near, mid and long-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the Renfrew Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service.

Sections 6.1- 6.5 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 Station Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transformer Stations within the Renfrew region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 6-1 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 6-1 Renfrew Region – Station capacity needs

Sr.no.	Station Name	Station LTR (MW) (Summer/Winter)	2022 Loading (MW) (Summer/Winter)	Need Date
1	Pembroke TS	47/57 MW	48/53 MW	Current
2	Forest Lea DS	8.6/11.6 MW	9/11 MW	Current
3	Petawawa DS	16.3/20.2 MW	10/10 MW	*

* Identified during IRRP phase but was eliminated in RIP following the load forecast update for Petawawa DS.

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Transmission Line Capacity Needs

Over the study period 2022-2042 RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Renfrew region. It was determined that all Transmission Lines are within the thermal limits of the circuits and within the voltage range as per ORTAC over the study period adequate over the study period for the loss of a single 230/115 kV circuit in the Region.

6.3 Asset Renewal for Major HV Transmission Equipment

Hydro One is the only Transmission Asset Owner (TAO) in the Renfrew region. Hydro One facilities in the region that will require replacement over the near-medium -term period as listed in Table 6-2 below.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers.
- 230 and 115kV breakers where:
  - replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
  - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 6-2 Renfrew Region - Planned Replacement Work

Station/Circuit	Need Description	Planned ISD
D6	Complete 76.8kM line refurbishment between Des Joachims TS and Petawawa/Craig DS	2025

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

6.5 Long Term Needs

During IRRP phase, a long-term supply capacity issue has been identified under high growth scenarios in the Des Joachims sub-system. The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region.
The options and preferred solution to address this need is discussed further in Section 7 of the report.

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility.

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE RENFREW REGION.

The electrical infrastructure needs for the Renfrew Region are summarized in Table 7-1. These needs include those previously identified in the NA and IRRP for the Renfrew region. All estimated costs included in the alternative analysis are considered as planning estimates and are used for comparative purposes only.

Table 7-1 Renfrew Region – Near, Medium- and Long-Term Needs

Station/Circuit Name	Description of Need	Need Date	RIP Report Section
Station Capacity Needs			
Pembroke TS	Station has exceeded its summer LTR	Current	7.1.1
Forest Lea DS	Station has exceeded its summer LTR	Current	7.1.2
Petawawa DS	Station was expected to exceed its summer LTR	*	7.1.3
Long Term Needs			
Des Joachims sub-system	Supply capacity issue in long-term under high growth scenario	2034	7.5.1

* Identified during IRRP phase but was eliminated in RIP following the load forecast update.

7.1 Station Capacity Needs

A station capacity assessment was performed over the study period 2022-2042 for the 230kV and 115kV transforming stations in the Renfrew region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following station capacity needs have been identified in the during the study period:

7.1.1 Pembroke TS – 115kV

Pembroke TS supplies Hydro One Dx while ORPC is an embedded LDC. It is a 115/44 kV Transmission Station (TS) with two 25/33/42 MVA (T1/T2) transformers supplied by circuits X2Y & X6 with a summer and winter LTR of 47 MW and 57 MW, respectively.

Pembroke TS has three distribution feeders which supplies Hydro One Distribution, with ORPC as an embedded LDC on two feeders. This station has exceeded its normal supply capacity in 2019 and TWG has agreed that a wires solution is required to address this need.

The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Build a new HVDS:
A new HVDS would be built near Pembroke TS. An HVDS would provide 18 MW of capacity at an approximate cost of $14M, which includes $11M for building the station and at a least an additional $3M for distribution costs. The new HVDS would be connected to 115kV circuit X6 as during contingency it is less limiting than X2Y as the overall circuit have a higher thermal rating compared to X2Y. The Pembroke DS load, which is expected to be 6 MW, will be transferred to the new HVDS, therefore freeing up capacity for new load on Pembroke TS. The remaining capacity of new HVDS would also be able to supply an additional 12MW of new load at 12kV in the area. Although connecting a HVDS to one circuit is less reliable than a TS connected to both circuits as it does not provide full redundant supply, there is an existing transmission 115kV switch at Cobden TS that can be used to tie X2Y and X6 to restore the load on the new HVDS for in case of a fault East of Cobden TS. All of ORPC load is currently supplied by the existing two 44kV feeders from Pembroke TS. Due to the current distribution configuration of the ORPC system, future ORPC load from the new HVDS will require further modifications at ORPC's operating system within its service territory.

From a capacity standpoint, this option would be able to supply all the forecasted load in area for the long term.

Alternative 3 – Build a new Transmission Station (TS):
Build a new TS consisting of two 115/44 kV 25/33/42 MVA step-down transformers near the existing Pembroke TS, connected to both the X2Y and X6 circuits. This would cost approximately $30M. The new supply station will be able to supply 47 MW, which is more than sufficient for the 20-year load forecast, including Pembroke TS long term growth. Similar to the HVDS option, 115kV circuit X2Y is more limiting and during a contingency situation, the thermally limiting sections on X2Y will prevent the new TS from supplying the full 47 MW station capacity.

Recommendation:
Both alternatives 2 and 3 addresses the need for additional capacity at Pembroke TS during normal operations. However, building a new TS is significantly more expensive than building a new HVDS and will also require an additional cost for transmission line upgrades to utilize the full station capacity. Building a new HVDS which is a less costly alternative, has its own operational limitations and complications for ORPC. As the assessment of both alternatives are very complex, further discussion between Hydro One Tx and the impacted LDCs is required. Both Hydro One Dx and ORPC will continue to explore these two options to determine the most feasible solution to address the capacity need at Pembroke TS.

7.1.2 Forest Lea DS – 115kV

Forest Lea DS is located in Laurentian Valley Hills, outside the city of Pembroke. It is connected at the tail end of the circuit D6, after Petawawa DS and Craig DS. This station is owned and operated by Hydro One Dx. Forest Lea DS is a 115/13.4 kV Step down station and is radially supplied by circuit D6 it has two 7.5/11 MVA (T1/T2) transformers with a summer LTR of 8.6 MW and winter LTR of 11.1 MW.

This station has already exceeded its normal supply capacity but will only increase by slightly over the station LTR at the end of the study period. The TWG has agreed that a solution is required to address this need.
The following alternatives were considered to address the need:

Alternative 1 - Maintain Status Quo:
This solution is not recommended as it does not address the supply capacity need at the station and will prevent future load growth at this station.

Alternative 2 – Load Transfer:
Through existing Dx interties, there is a possibility of transferring load to the Pembroke DS and Craig DS. TWG confirmed that a 1 MW load transfer to Craig DS can be done with minimal work with a capital cost of only $50k. A transfer to Pembroke DS, is also technically feasible, but would result in a further overload of the upstream Pembroke TS and the outcome of the preferred solution for Pembroke TS station capacity issue could affect the load transfer. In light of all these reasons, load transfer at Craig DS is preferred.

Alternative 3 – Upgrading the supply capacity:
The capacity of Forest Lea station can be upgraded using two methods which are:
i) Upgrading the transformers to add 10 MW of capacity for a capital cost of $4.5M or,
ii) Installing fan cooling and SCADA monitoring system to the existing transformers to add 4 MW at a capital cost of $0.6M.

Alternative 4 – Building new HVDS:
It is also possible to build a new HVDS for the Forest Lea area which will add 18 MW of load at a capital cost of $12M. This option will provide a higher capacity, which is not required at this moment, even under consideration of a high growth scenario.

Recommendation:
The need of station capacity at Forest Lea DS is current, but the expected load growth is very low. The load at this station is only expected to grow to slightly over 1 MW in the long-term. Hence, load transfer to Craig TS is considered as the most appropriate as well as cost effective alternative. TWG recommends and agrees to transfer 2 MW load to Craig DS. The expected completion date for this load transfer is 2026.

7.1.3 Petawawa DS – 115kV

Petawawa DS supplies the town of Petawawa and a large customer. The majority of the load i.e., 80% of the total load, is consumed by this large customer. The station is radially supplied by D6 and is located at the end of the circuit, right after Craig DS. It has two 115/13.4 kV Step down 7.5/10/13 MVA (T1/T2) transformers with a summer LTR of about 16 MW and winter LTR of 20 MW.

As per the IRRP Load Forecast the station reaches its summer LTR in 2030 and hence recommended to build a new HVDS transformer station at Petawawa with in-service date of 2027. During the RIP phase it was observed that the load increased abnormally in June 2020 due to generator refurbishment work at the customer's facility in Petawawa DS and resulted in the net load increase by 3 MW at the station. This work was completed in July 2020. As the load displacement generation is permanently operating, the net load at the station returned to its normal value resulting in a net load of approximately 9.8 MW during the year 2021. Hence, the Load Forecast for

Petawawa DS was updated in the RIP, and the 2022 load was determined by considering the actual load in 2021. The updated load forecast yields a lower Net Load at the end of study period.

Recommendation:
Since the elevated load forecast was updated for actual value, the load at Petawawa DS remains below the summer/winter (16.3/20.2 MW) LTRs for the long-term forecast. However, during the IRRP phase the customers in this area have indicated some possible future expansion and heating load conversion under Canadian Net-Zero Emissions Accountability Act that was considered in a high load growth scenario. Hence, for now it is recommended to defer this need as no additional capacity is required at this station for the short to medium term, but the TWG will continue to monitor the future high load growth scenario and trigger regional planning earlier if and when demand arises at the station.

7.2 Transmission Line Capacity Needs

All line and equipment load shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2022-2042 for the 230kV and 115kV Transmission line circuits in the Renfrew region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, no new Transmission line capacity needs were identified in the region during the study period.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for “right sizing” the equipment:

- Maintaining the status quo;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards;
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities;
- Eliminating equipment by transferring all the load to other existing facilities;
- Replacing equipment with similar equipment and built to current standards (i.e., “like-for-like” replacement);
- Replacing equipment with higher ratings and built to current standards.

From Hydro One’s perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.
No new major HV Asset Renewal Needs were identified in the region during the study period.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2022-2042 to cater this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

7.5 Long Term Considerations

7.5.1 Des Joachims sub-system – Supply capacity issue

The Des Joachims sub-system refers to transmission line D6 connected to the Des Joachims TS in the west of Renfrew region and ends at Petawawa DS and Forest Lea DS in the east. During IRRP, two high growth scenarios (i.e., increase in load by 20MW & 40MW) were identified as a part of the engagement process for the Des Joachims sub-system. The LMC of Des Joachims sub-system is approximately 80MW and under high growth scenarios, with one element out and a contingency to a generator at Des Joachims TS, under peak coincident demand and low generation conditions, voltage change violations are identified at the stations connected to the end of D6 circuit.

Alternative 1 - Maintain Status Quo:
The need is identified in the medium to long-term, and both high load growth scenarios have fair amount of uncertainties. Monitor the current load growth in the area and maintain status quo until next regional planning cycle.

Alternative 2 – Capacitor banks:
Installing capacitor banks at either Craig DS, Petawawa DS or Forest Lea DS will improve the LMC by approximately 10 MW and can support the first high growth scenario i.e., a load growth of over 20 MW.

Alternative 2 – Transmission options:
For the more aggressive load growth scenario, i.e., load growth of over 40MW, the support provided by capacitor banks will not be enough and there will be a need to construct new transmission line in the area.

Recommendation:
The need is identified in the mid to long-term, and in light of uncertainties of the load growth in the sub-system. Hence, for now it is recommended that TWG will continue to monitor the future high load growth scenario and if required can proceed with the capacitor upgrade if and when need arises.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE RENFREW REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near, medium and long-term are provided in Table 8-1 below, along with their planned in-service dates and estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the 2022-2042 Study Period

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Station capacity needs				
Pembroke TS	Hydro One Dx and ORPC to continue to explore both the new TS and HVDS options and determine most feasible solution	Hydro One Tx	2028	14-30
Forest Lea DS	Transfer 2 MW load to Craig TS	Hydro One Dx	2026	0.05
Petawawa DS	No longer needed as Load Forecast is revised.	Hydro One Dx	-	-
Long-term Supply capacity needs				
Des Joachims sub-system	Monitor load growth in the area and wait for confirmation of investments.	IESO	-	-

Note:
a) The planned in-service dates are tentative and subject to change.
b) Costs are based on planning estimates may exclude the cost for distribution infrastructure (if required)

9. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

[5] Independent Electricity System Operator, Renfrew region IRRP Cycle-2 (December, 2022)

[6] Independent Electricity System Operator, Renfrew region Scoping Assessment Cycle-2 (August, 2021)

[7] Hydro One Networks Inc., Renfrew region Needs Assessment Cycle-2 (May 2021)

APPENDIX A. RENFREW REGION - STATIONS

Sr. No.	Transformer Station	Voltage (kV)	Supply Circuits
1.	Cobden DS (T3)	115/12.5	X2Y
2.	Cobden TS (T1/T2)	115/44	X2Y/X6
3.	Craig DS (T1/T2)	115/12.5	D6
4.	Deep River DS (T1/T2/T3)	115/12.5	D6
5.	Des Joachims DS (T1)	115/12.5	D6
6.	Forest Lea DS (T1/T2)	115/12.5	D6
7.	Mazinaw DS (T1/T2)	230/12.5	X1P
9.	Pembroke TS (T1/T2)	115/44	X2Y/X6
10.	Petawawa DS (T1/T2)	115/12.5	D6

APPENDIX B. RENFREW REGION - TRANSMISSION LINES

Sr. No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Des Joachims DS to Pembroke TS	D6	115
2	Chenaux TS to Pembroke TS	X6	115
3	Chenaux TS to Pembroke TS	X2Y	115
4	Dobbin TS to Chenaux TS	X1P	230

APPENDIX C. RENFREW REGION - DISTRIBUTORS

Sr. no.	Name of LDC
1	Hydro One Networks Inc.(Distribution)
2	Ottawa River Power Corporation (ORPC)

APPENDIX D. RENFREW REGION - MUNICIPALITIES

Sr. no.	Name of Municipality
1	Town of Arnprior
2	Town of Deep River
3	Town of Laurentian Hills
4	Town of Petawawa and Renfrew
5	Township of Admaston/Bromley
6	Township of Bonnechere Valley
7	Township of Brudenell
8	Township of Lyndoch and Raglan
9	Township of Greater Madawaska
10	Township of Head
11	Township of Clara and Maria Horton
12	Township of Killaloe
13	Township of Hagarty and Richards
14	Township of Laurentian Valley
15	Township of Madawaska Valley
16	Township of McNab/Braeside
17	Township of North Algona Wilberforce and Whitewater Region
18	City of Pembroke

APPENDIX E. RENFREW REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	**7.0**	**7.0**	**7.0**	**7.1**	**7.1**	**7.1**	**7.1**	**7.2**	**7.2**	**7.2**	**7.2**	**7.2**	**7.3**	**7.2**	**8.2**	**8.2**	**8.2**	**8.2**	**8.2**	**8.2**	**8.2**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8	8
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	**3.0**	**3.0**	**3.0**	**3.0**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**	**3.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Cobden DS	Tx	T3	N/A	N/A	9.4	Load	**7.1**	**7.2**	**7.3**	**7.3**	**7.4**	**7.4**	**7.5**	**7.6**	**7.6**	**7.7**	**7.7**	**7.8**	**7.8**	**7.8**	**7.9**	**8.9**	**8.9**	**8.9**	**8.9**	**8.9**	**8.9**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	47.8	Load	**23.9**	**24.1**	**24.3**	**25.5**	**25.7**	**25.9**	**26.1**	**26.3**	**26.4**	**26.6**	**26.8**	**27.0**	**27.1**	**27.2**	**27.3**	**28.3**	**28.3**	**28.3**	**28.3**	**28.3**	**29.3**
						DG	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5
						CDM	0.4	0.6	0.8	1	1.2	1.4	1.6	1.8	1.9	2.1	2.3	2.5	2.6	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.8
						Net	22	22	22	23	23	23	23	23	23	23	23	23	23	23	23	24	24	24	24	24	25
Craig DS	Tx	T1/T2	B1B2	N/A	19.9	Load	**14.3**	**14.4**	**14.5**	**15.6**	**15.7**	**15.9**	**16.0**	**16.1**	**16.2**	**16.3**	**16.4**	**16.5**	**17.6**	**17.6**	**17.7**	**17.7**	**17.7**	**17.7**	**18.7**	**18.7**	**18.8**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.3	0.4	0.5	0.6	0.7	0.9	1	1.1	1.2	1.3	1.4	1.5	1.6	1.6	1.7	1.7	1.7	1.7	1.7	1.7	1.8
						Net	14	14	14	15	15	15	15	15	15	15	15	15	16	16	16	16	16	16	17	17	17
Deep River DS	Tx	T1/T2/T3	N/A	N/A	8.6	Load	**8.2**	**8.3**	**8.3**	**8.4**	**9.5**	**9.5**	**10.6**	**10.7**	**10.7**	**10.8**	**10.8**	**10.9**	**10.9**	**11.0**	**11.0**	**11.0**	**11.0**	**11.0**	**11.0**	**11.0**	**11.0**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1	1	1	1	1	1	1	1
						Net	8	8	8	8	9	9	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Des Joachims DS	Tx	T1	N/A	N/A	9.4	Load	**2.0**	**2.1**	**2.1**	**2.1**	**2.1**	**2.1**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.2**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**	**2.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Forest Lea DS	Tx	T1/T2	BY	N/A	8.6	Load	**9.1**	**9.2**	**9.3**	**9.4**	**9.4**	**9.5**	**9.6**	**9.7**	**9.7**	**9.8**	**9.9**	**9.9**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.0**	**10.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1	1	1	1	1	1	1	1	1.1
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Mazinaw DS	Tx	T1	BY	N/A	6.9	Load	**3.1**	**3.1**	**3.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**	**4.4**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
						Net	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Mountain Chute DS	Tx	T1	BY	N/A	8.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	47	Load	**48.5**	**48.6**	**49.9**	**50.2**	**51.5**	**51.7**	**52.9**	**53.1**	**54.5**	**54.7**	**55.9**	**56.1**	**57.2**	**58.2**	**59.3**	**60.3**	**60.3**	**61.3**	**62.4**	**63.4**	**64.4**
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.3	0.4	0.7	1	1.3	1.5	1.7	1.9	2.3	2.5	2.7	2.9	3	3	3.1	3.1	3.1	3.1	3.2	3.2	3.2
						Net	48	48	49	49	50	50	51	51	52	52	53	53	54	55	56	57	57	58	59	60	61
Petawawa DS	Tx	T1/T2	BY	N/A	16.3	Load	**10.5**	**10.9**	**11.3**	**11.6**	**11.9**	**12.3**	**12.6**	**12.9**	**13.2**	**13.6**	**13.9**	**14.2**	**14.4**	**14.8**	**15.1**	**15.3**	**15.6**	**15.8**	**16.2**	**16.3**	**16.6**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.5	0.7	0.9	1	1.1	1.3	1.4	1.5	1.6	1.7	1.8	1.9	1.9	2	2.1	2.1	2.1	2.1	2.2	2.1	2.1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

Winter Net Non-Coincident Load Forecast

Transformer Station Name	Connection Tx / Dx	DESN ID (e.g., T1/T2)	Bus ID (e.g., BY)	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
							2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
CTS-1	Tx	N/A	N/A	N/A	N/A	Load	**9.0**	**9.0**	**9.0**	**9.1**	**9.1**	**9.1**	**9.2**	**9.2**	**9.3**	**9.3**	**9.3**	**9.3**	**9.3**	**9.3**	**10.3**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0.1	0.1	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2
						Net	9	9	9	9	9	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10
CTS-2	Tx	N/A	N/A	N/A	N/A	Load	**4.0**	**4.0**	**4.0**	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Cobden DS	Tx	T3	N/A	N/A	12	Load	**7.1**	**7.1**	**7.1**	**7.2**	**7.2**	**7.2**	**7.2**	**7.3**	**7.3**	**7.4**	**7.4**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**7.5**	**8.5**	**8.5**	**8.5**	**8.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
						Net	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	8
Cobden TS	Tx	T1/T2	N/A	M2 M6	54.7	Load	**25.4**	**25.6**	**25.7**	**25.8**	**25.9**	**26.0**	**26.1**	**26.3**	**26.5**	**26.6**	**27.8**	**27.9**	**28.0**	**28.1**	**28.1**	**28.1**	**29.1**	**29.1**	**29.1**	**29.1**	**30.2**
						DG	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
						CDM	0.2	0.4	0.5	0.6	0.7	0.8	0.9	1.1	1.3	1.4	1.6	1.7	1.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2
						Net	25	25	25	25	25	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	28
Craig DS	Tx	T1/T2	B1B2	N/A	23.2	Load	**12.1**	**12.2**	**12.2**	**12.3**	**13.3**	**13.4**	**13.4**	**13.5**	**13.6**	**13.7**	**13.7**	**13.8**	**13.9**	**14.9**	**14.9**	**14.9**	**14.9**	**14.9**	**14.9**	**15.9**	**16.0**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1
						Net	12	12	12	12	13	13	13	13	13	13	13	13	13	14	14	14	14	14	14	15	15
Deep River DS	Tx	T1/T2/T3	N/A	N/A	11.6	Load	**10.1**	**10.2**	**10.2**	**10.3**	**11.3**	**11.4**	**12.4**	**12.5**	**12.5**	**12.6**	**12.6**	**12.7**	**12.7**	**12.7**	**12.8**	**12.8**	**12.8**	**12.8**	**12.8**	**12.8**	**12.8**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8

Transformer Station Name	Connection Tx / Dx	DESN ID	Bus ID	Feeder(s)	LTR	Type	Near Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast					Medium Term Forecast (MW) Gross Peak Load Forecast										
		(e.g., T1/T2)	(e.g., BY)				2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
						Net	10	10	10	10	11	11	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
Des Joachims DS	Tx	T1	N/A	N/A	12	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.2**	**3.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	3	4	4	4	4	4	4	4	4	4
Forest Lea DS	Tx	T1/T2	BY	N/A	11.6	Load	**11.1**	**11.2**	**11.2**	**11.3**	**11.3**	**11.4**	**11.4**	**11.5**	**11.6**	**11.6**	**11.7**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**11.8**	**12.8**	**12.8**	**12.9**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.9
						Net	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	12	12	12
Mazinaw DS	Tx	T1	BY	N/A	9.3	Load	**4.0**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**4.3**	**5.3**	**5.3**	**5.3**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
						Net	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
Mountain Chute DS	Tx	T1	BY	N/A	11.6	Load	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.0**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**	**1.1**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0	0	0	0	0	0	0	0	0	0	0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
						Net	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Pembroke TS	Tx	T1/T2	JQ	M1 M2 M3	57	Load	**53.1**	**53.2**	**54.5**	**54.8**	**55.0**	**56.2**	**56.3**	**57.6**	**57.9**	**59.1**	**59.3**	**60.5**	**60.6**	**61.6**	**62.5**	**63.6**	**64.6**	**65.6**	**66.5**	**67.5**	**68.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.1	0.2	0.5	0.8	1	1.2	1.3	1.6	1.9	2.1	2.3	2.5	2.6	2.6	2.5	2.6	2.6	2.6	2.5	2.5	2.5
						Net	53	53	54	54	54	55	55	56	56	57	57	58	58	59	60	61	62	63	64	65	66
Petawawa DS	Tx	T1/T2	BY	N/A	20.2	Load	**10.2**	**10.5**	**10.8**	**11.0**	**11.3**	**11.5**	**11.8**	**12.0**	**12.3**	**12.6**	**12.9**	**13.1**	**13.4**	**13.7**	**13.9**	**14.1**	**14.4**	**14.6**	**14.9**	**15.2**	**15.5**
						DG	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
						CDM	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	1	1
						Net	10.0	10.2	10.4	10.6	10.8	11.0	11.2	11.4	11.6	11.9	12.1	12.3	12.5	12.8	13.0	13.2	13.5	13.7	14.0	14.2	14.5

APPENDIX F. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme
TWG	Technical Working Group