Sudbury/Algoma

2020 REGIONAL INFRASTRUCTURE PLAN
DECEMBER 16, 2020

hydro one

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Prepared and supported by:

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Disclaimer

This Regional Infrastructure Plan (RIP) report is an electricity infrastructure plan that identifies and addresses near and mid-term needs based on information provided and/or collected by the Study Team.

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 Study Team.

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EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) WAS PREPARED BY HYDRO ONE WITH PARTICIPATION AND INPUT FROM THE RIP STUDY TEAM IN ACCORDANCE WITH THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE PLANNED, DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE SUDBURY/ALGOMA REGION.

The participants of the Regional Planning activities for the Sudbury/Algoma region ('the Study Team')included members from the following organizations:

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)
- North Bay Hydro (Embedded LDC)
- Independent Electricity System Operator (IESO)
- Hydro One Networks Inc. (Lead Transmitter)

The last regional planning cycle for the Sudbury/Algoma region was completed in June 2016 with the publication of the RIP report.

This RIP is the final phase of the 2nd regional planning cycle and follows the 2nd Cycle Sudbury/Algoma region's Needs Assessment (NA) completed in August 2020. Based on the findings of the NA, the Study Team recommended no further regional coordination is required at this time. Hence, this RIP is based on the data collected during the NA phase and the findings and recommendations of the NA report. A new Energy Efficiency framework was announced by the Ontario Government since the completion of the NA of the Sudbury/Algoma region. Resulting impacts of the newly announced framework are not reflected in the present RIP.

This RIP provides a consolidated summary of the outcome of the needs and recommended plans for the Sudbury/Algoma region as identified by the regional planning study team. The RIP also discusses needs identified in the previous regional planning cycle and the NA report for this cycle; and the projects developed to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the initiation of the previous regional planning cycle, the following project has been completed:

- **Espanola TS**: Replace 115/44 kV 15MVA (T1) and 42MVA (T2) transformers with new 115/44 kV 42 MVA units. These transformers were assessed at being at their end-of-life and in need of replacement due to the assets'condition. This project was successfully carried out and in serviced in Q4 2016.

- **Larchwood TS** – Replace 110/44 kV 20 MVA (T2) transformer with a new 115/44kV 42MVA unit. This project was successfully completed and in serviced in Q4 2015.

The major infrastructure investments identified and supported by the Study Team over the near- and mid-term planning horizon are provided in Table 1 below, along with their planned in service dates and budgetary allowances for planning purpose.

Table 1: Recommended Plans in Sudbury/Algoma region over the Next 10 Years

No.	Needs	Plans	Planned I/S Date	Budgetary Allowance ($M)
1	Manitoulin TS Capacity Constraint	Change limiting CT ratio	2021	0.02
2	Under peak load conditions, the loss of two Martindale 230/115kV transformers may result in the overload of the third Martindale transformer	Martindale autotransformers T21/T23 Replacement project	2022[1]	76
3	With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable limits set out in the Ontario Ressources and Transmission Assessement Criteria(ORTAC) document	Unbundle X25S/X26S	2023	8
4	Elliot Lake TS end-of-life (EOL) Power Transformer Replacement	Right-sizing that station by replacing 115/44 kV 42 MVA (T1) power transformer with new 115/44kV 42 MVA unit. Remove 115/44 kV 19 MVA (T2) 8autotransformer. Upon completion of this project, the station will remain with 2 – 115/44kV 42 MVA (T1/T3) power transformers.	2025	23
5	Algoma TS end-of-life (EOL) autotransformer replacement	Replace 230/115kV 195 MVA and 115 MVA autotransformers (respectively T5 and T6) with new 230/115kV 125 MVA transformers.	2025	23
6	Clarabelle TS end-of-llife (EOL) Power transformer Replacement	Replace 230/44kV 125 MVA (T1/T2) power transformers with new 230/44kV 125 MVA units.	2027	19
7	Martindale TS end-of-life (EOL) Power Transformer Replacement	Replace 230/44 kV 125 MVA (T1/T2) power transformers with new 230/44 kV 125 MVA units.	2028	19
8	Martindale TS Supply Capacity Constraint	Maintain the status quo and reassess station supply needs during the next Regional Planning Cycle	2028	N/A

The Study Team recommends the continuation of the investments listed in Table 1. Hydro One transmission will coordinate with affected LDCs to implement these undertakings.

[1] Earlier Regional Planning documents indicate 2020 as the planned in service date for this project. Needs reprioritization as well as current pandemic conditions resulted in pushing the targeted completion date for this undertaking to 2022.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SUDBURY/ALGOMA REGION BETWEEN 2020 AND 2029.

The report was prepared by Hydro One Networks Inc. (HONI) with input from Study Team members during the Needs Assessement (NA) phase and documents the results of the NA and recommended plan. The Study Team included representative from Greater Sudbury Hydro Inc, North Bay Hydro, HONI(Transmission and Distribution) and the Independent Electricity System Operator (IESO) in accordance with the Regional Planning process established by the Ontario Energy Board (OEB) in 2013.

The Sudbury to Algoma Region includes Greater Sudbury Area, Manitoulin Island, and townships of Verner, Warren, Elliot Lake, Blind River and Walden. The boundaries of the Sudbury to Algoma Region are shown below in Figure 1.

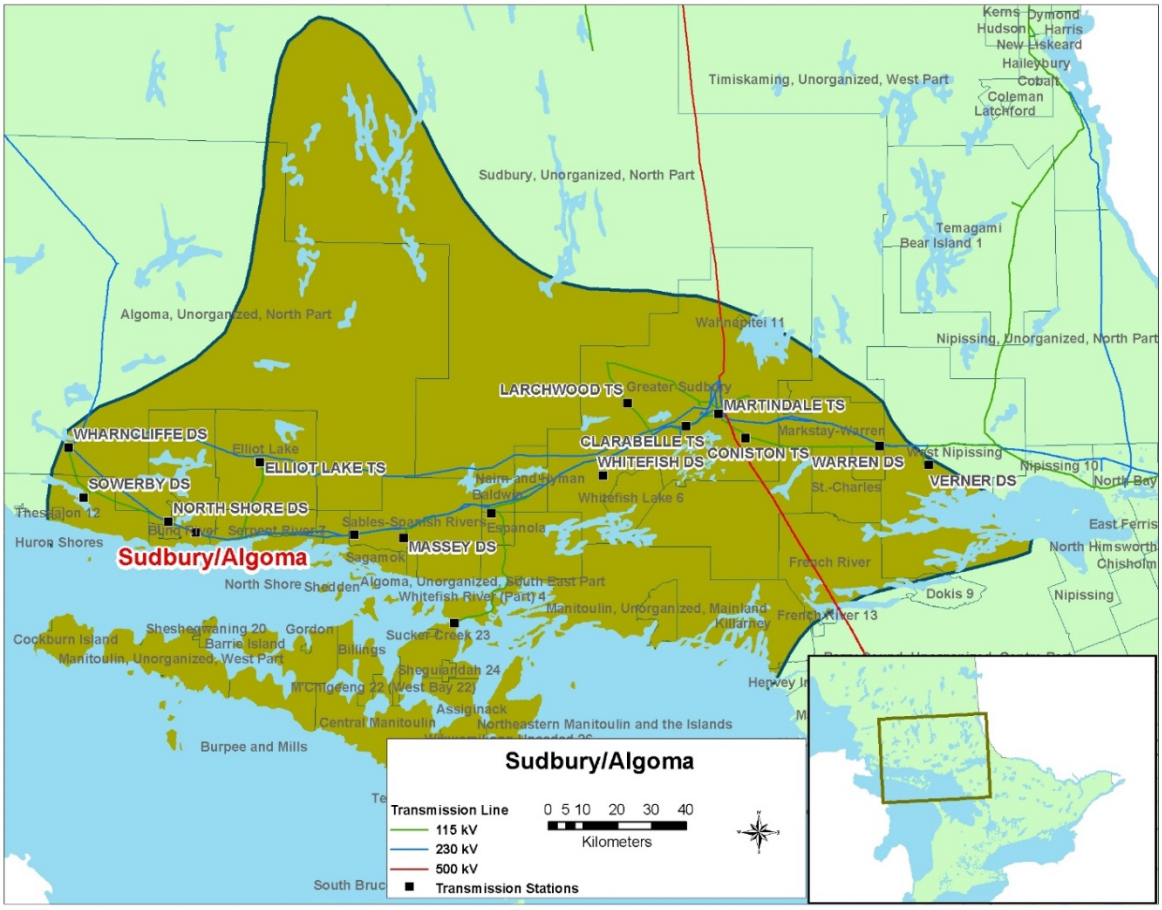

Figure 1-1: Sudbury/Algoma region

Electrical supply to the Sudbury/Algoma region is provided through a network of 230kV and 115kV transmission circuits supplied by autotransformers at Hanmer TS, Algoma TS and Martindale TS. This area is further reinforced through the 500kV circuits (P502X and X504/503E) connecting Hanmer TS

(Sudbury) to both Porcupine TS (Timmins) and Essa TS (Barrie). It is also connected to northwest Ontario through Mississagi TS

1.1 Objective and Scope

The RIP report examines the needs in the Sudbury/Algoma region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., NA and/or Integrated Regional Resource Plan(IRRP);
- Assess and develop a wires plan to address these new needs; and
- 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, major high voltage sustainment issues emerging over the near, mid and long-term, 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. A new Energy Efficiency framework was announced by the Ontario Government since the completion of the NA of the Sudbury/Algoma region. This RIP does not take into account the resulting impact of the newly announced CDM framework.

The scope of this RIP is as follows:

- Discussion of any other major transmission infrastructure investment plans over the near, mid and long-term (0-20 years)
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information, if any.

As mentioned this particular RIP is based on the information collected and recommendations from the NA phase of regional planning because no further regional coordination or assessments were required.

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 and identifies needs.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- 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 (OEB) in 2013 through amendments to the Transmission System Code (TSC) and Distribution System Code (DSC). The process consists of four phases: the Needs Assessment [2] (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 Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company (LDC) or customer and develops a Local Plan (LP) to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision 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 was 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 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 that the IRRP identifies as best suited to meet a need are then

[2] Also referred to as Needs Screening

further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities and establishes a Local Advisory Committee in the region or sub-region.

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion and reconfirmation 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 the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive 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 efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect.
- The NA, SA, and LP phases of regional planning.
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region.
- Working and 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.

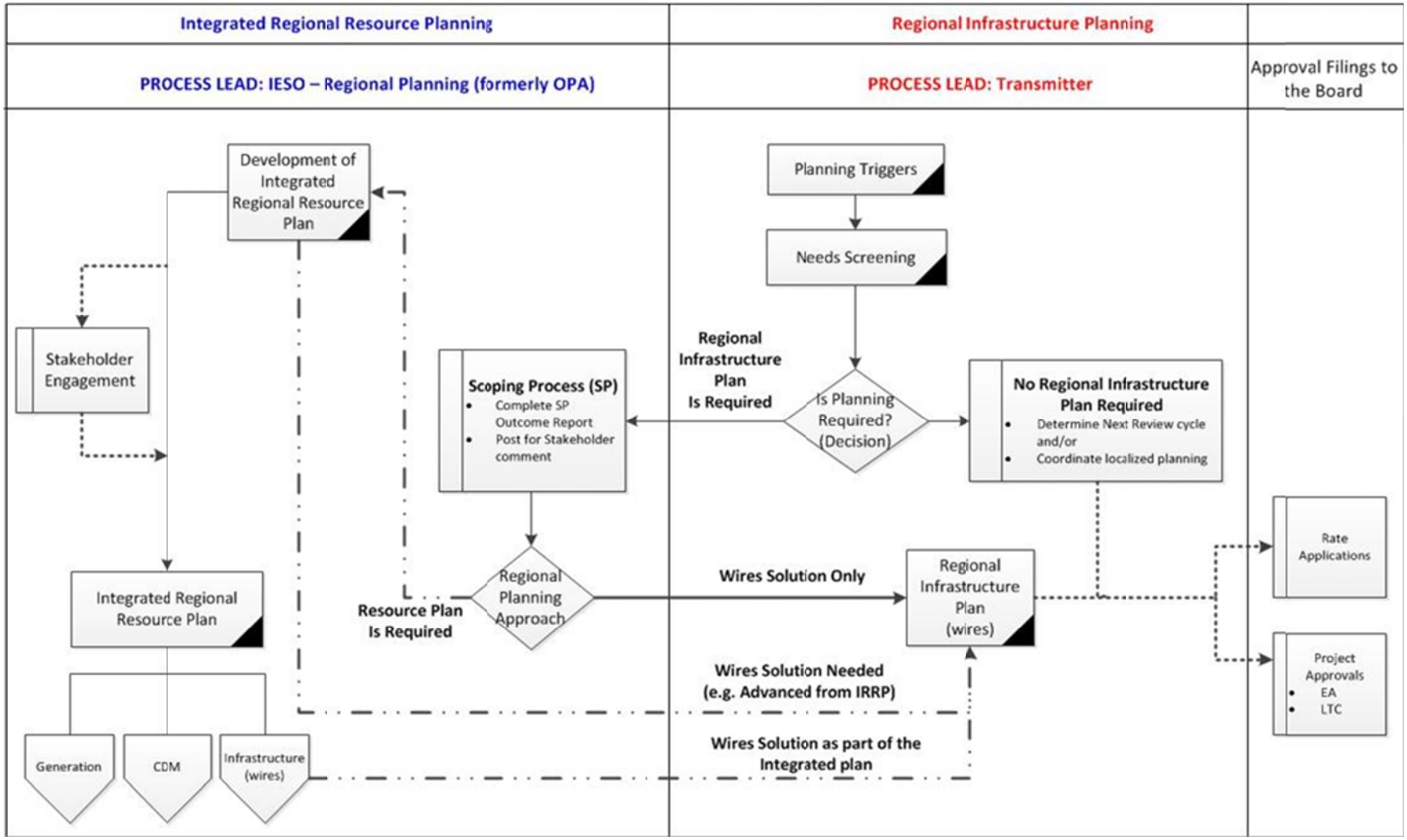

Figure 2-1: Regional Planning Process Flowchart

For the Sudbury/Algoma region, no need was identified that requires regional coordination. Hence,the Regional Planning process for the region moved directly to its RIP phase following the completion of the NA phase.

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1. Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team 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.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; 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. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.
3. Alternative Development: The third step is the development of wires options to address the needs and to come up with 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.

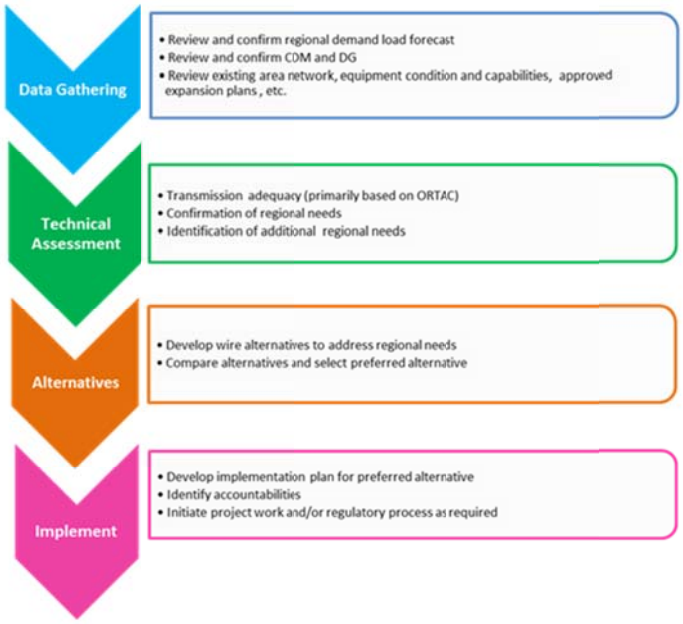

Figure 2-2: RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SUDBURY/ALGOMA REGION IS COMPRISED OF THE GREATER SUBDURY AREA, MANITOULIN ISLAND AND THE TOWNSHIPS OF VERNER, WARREN, ELLIOT LAKE AND WALDEN. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED THROUGH A NETWORK OF 230KV AND 115KV CIRCUITS SUPPLIED FROM AUTOTRANSFORMERS AT HANMER TS, ALGOMA TS AND MARTINDALE TS.

Bulk electrical supply to the Sudbury/Algoma region is currently provided through Hanmer TS, Algoma TS and Martindale TS, three (3) major autotransformers station in the region. This area is further reinforced through the 500 kV circuits (P502X and X503/504E) connecting Hanmer TS (in Sudbury) to Porcupine TS (in Timmins) and Essa TS (in Barrie). The area is also connected to the north western Ontario through Mississagi TS.

This region has the following two transmission-connected local distribution companies (LDC):

- Greater Sudbury Hydro Inc.
- Hydro One Networks Inc. (Distribution)

North Bay Hydro is a third LDC in this region embedded into the Hydro One Disribution system. Although invited to participate directly in the NA process, the data related to this LDC as well as their operational concerns was communicated through their host LDC Hydro One Distribution.

Tranmission connected industrial/commercial loads in the Sudbury to Algoma region form a large percentage (approximately 50%) of the overall demand. Although these customers are not explicitly participating in the regional planning process, Hydro One will consider their impact in the RIP of this region.

Below is a description of the major assets in the region:

- Hanmer TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Algoma TS (230 kV) and Martindale TS (230 kV) are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Eight (8) step-down transformer stations supply the Sudbury/Algoma load Algoma TS (115 kV), Martindale TS (115 kV), Coniston TS[3], Larchwood TS, Manitoulin TS, Espanola TS, Clarabelle TS, Elliot Lake TS. There are also nine HVDS that supply load in the Region: Sowerby DS, Wharncliffe DS, North Shore DS, Striker DS, Spanish DS, Massey DS, Whitefish DS, Warren DS and Verner DS.

[3] Coniston TS in its entirety is being decommissioned and removed.The load previously supplied from Coniston TS will be transferred onto Martindale TS DESN. The targeted completion date falls between now and the next Regional Planning Cycle for this region.

- Nine (9) Customer Transformer Stations (CTS) are supplied in the Region: Carmeuse Lime CTS, Sudbury Smelter CTS, Falconbridge CTS, Nickel Rim CTS, Eacom Nairn CTS, Onaping Area M&M CTS, Milman Foundry CTS, Vale Copper #4 CTS and Vale Frood Stbe #2 CTS.
- There are four (4) existing transmission connected generating stations (GS) in the region as follows:
    - Red Rock GS is a 40 MW hydro electric generation plant connected to circuit T1B
    - Rayner GS is a 42MW hydro electric generation plant connected to circuit T1B
    - McLean's Mountain Wind is a 60 MW wind farm connected to circuit S2B. It is located at the North end of the Manitoulin Island.
    - Aux Sables GS is a 5 MW hydro electric generation plant connected to 115kV circuit S2B
    - Serpent GS is a 8 MW hydro electric generation facility connected to 115kV circuit S2B

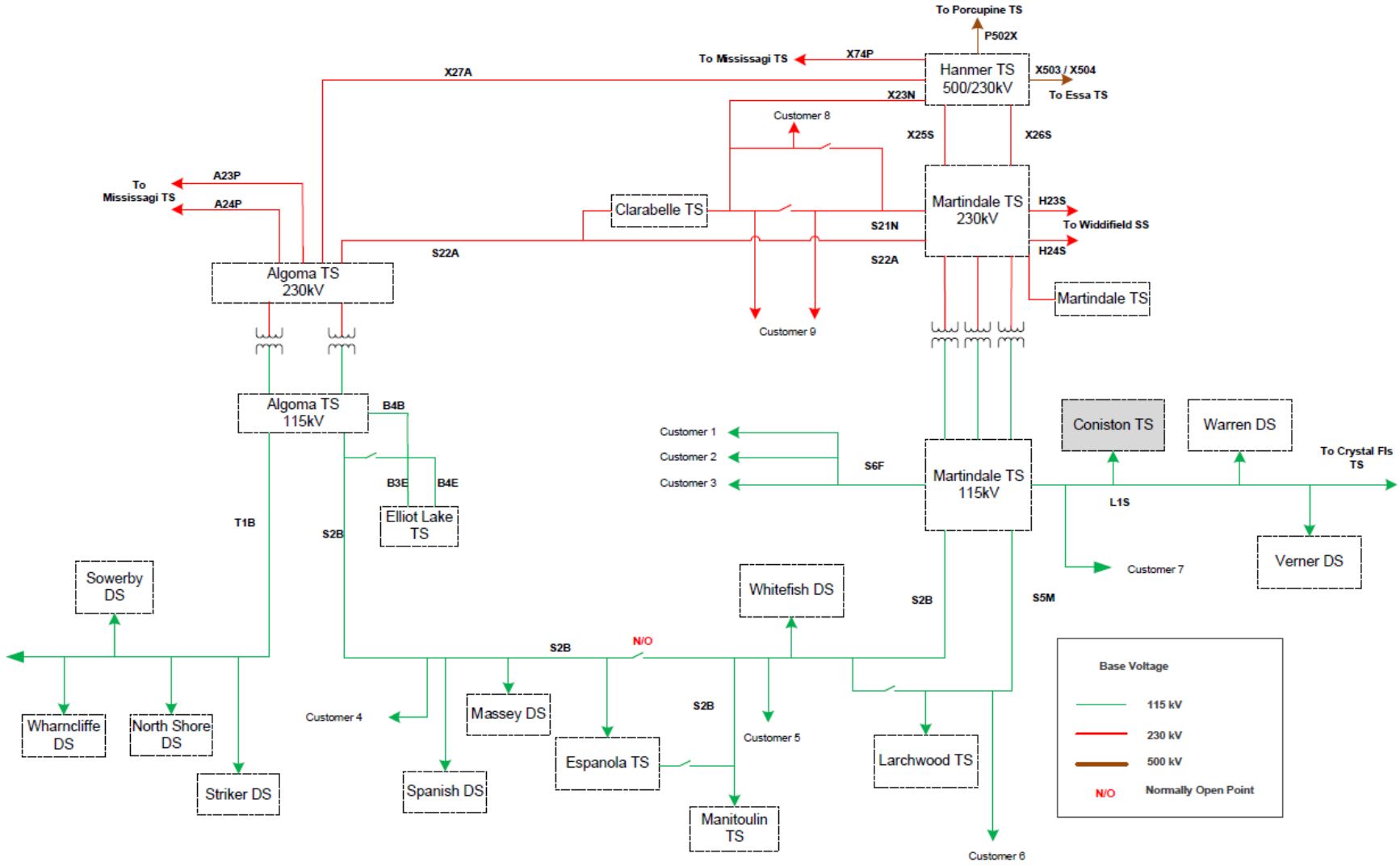

Figure 3-3: Single Line Diagram of Sudbury/Algoma Region

4. TRANSMISSION PROJECTS COMPLETED OVER LAST TEN YEARS

OVER THE LAST 10 YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND COMPLETED BY HYDRO ONE, IN CONSULTATION WITH THE LDCs AND/OR THE IESO, AIMED TO MAINTAIN OR IMPROVE THE RELIABILITY AND ADEQUACY OF SUPPLY IN THE SUDBURY/ALGOMA REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below:

i. **Espanola TS**: Replace 115/44 kV 15MVA (T1) and 42MVA (T2) transformers with new 115/44 kV 42 MVA units. These transformers were assessed at being at their end-of-life and in need of replacement due to the assets'condition. This project was successfully carried out and in serviced in Q4 2016.

ii. **Larchwood TS** – Replace 110/44 kV 20 MVA (T2) transformer with a new 115/44kV 42MVA unit. This project was successfully completed and in serviced in Q4 2015.

iii. **Coniston TS** - The previous Regional Planning cycle Needs Assessment makes mention of the removal of the Coniston TS and its load being transferred to a newly built Hanmer TS DESN. Due to customers's changing system needs, this plan was reviewed and it evolved into the removal of the station in concurrence with the conversion of the legacy 22kV loads to 27.6kV and their transfer onto one of the feeders originating from Martindale TS. Current pandemic conditions have slowed down the progression of this project. The project is currently planned to be completed in Q3 2021.

5. FORECAST AND OTHER STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the Sudbury/Algoma region for the 10 year study period. The IESO provided a CDM and Distributed Generation (DG) forecast for the Sudbury/Algoma region. The region's extreme winter non-coincident peak gross load forecast for each station was prepared by applying the LDC gross load forecast growth rates to the actual 2019/20 winter peak load corrected for extreme weather. The extreme weather correction factors were provided by Hydro One. The net extreme weather corrected winter load forecast was produced by reducing the gross load forecast for each station by the percentage CDM and by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that in the mid-term (5 to 10 year) time frame, contracts for existing DG resources in the region begin to expire, at which point the load forecast indicates a decreasing contribution from local DG resources, and thus an increase in net demand. These load forecasts for the individual stations in region are given in Appendix A. While the non-coincident load forecast was used to determine the need for station capacity, the coincident load forecast was used to assess the need for autotransformation and transmission line capacity in the region.

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2020-2029.
- All transmission facilities listed in Section 3 are in service.
- Where forecasts were not available, industrial loads were assumed based on historical information.
- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter 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.
- Line capacity adequacy is assessed by using coincident peak loads.
- Autotransformers capacity adequacy is assessed by using coincident peak loads.
- Normal planning supply capacity for transformer stations in this sub-region is determined by the Hydro One summer 10-Day Limited Time Rating (LTR).
- Adequacy assessment is conducted as per the Ontario Resource Transmission Assessment Criteria (ORTAC).

6. ADEQUACY OF FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION AND DELIVERY STATION FACILITIES SUPPLYING THE SUDBURY/ALGOMA REGION OVER THE 2020-2029 PERIOD.

Within the current regional planning cycle one regional assessment have been conducted for the Sudbury/Algoma region. The study is presented below:

The NA report principally identified two (2) needs within the study period and reaffirmed existing needs arising from EOL asset issues. A review of the loading on the transmission lines and stations in the Sudbury/Algoma region was also carried out as part of this RIP report using the latest regional load forecast as given in Appendix D. Sections 6.1 to 6.5 present the results of this review. Further description of assessments, alternatives and preferred plan along with status is provided in Section 7.

All the identified needs in the first cycle of the Regional Planning of the Sudbury/Algoma have been addressed. The low voltage at Manitoulin TS stems from the station being at the end of a long radial circuit under normal operating conditions. The power transformers at Manitoulin TS are equipped with under load tap changers with wide regulation bands (+/-20%) to maintain the LV side voltage within acceptable voltage limits. As such, Hydro One and the affected LDC are assured that the low voltage incidence at the Manitoulin TS high side connection point has no material impact on the system or its connected customers. Hydro One will continue to monitor the voltage performance at the Manitoulin TS high side connection point and will take the appropriate remedial actions if and when this low voltage incidence is deemed adversely impactive to customers and system reliability.

6.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Algoma TS and Martindale TS) supplying the Region are within their thermal limits and within the voltage range as per Ontario Resource and Transmission Assessment Criteria (ORTAC) over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.2 230 kV Transmission Lines

The 230 kV circuits supplying the Region are within their thermal limits as per ORTAC over the study period for the loss of a single 230 kV circuit in the Region.

6.3 115kV Transmission Lines

The 115 kV circuits supplying the Region are within the thermal limits of the circuits as per ORTAC over the study period adequate over the study period for the loss of a single 115 kV circuit in the Region.

6.4 230 kV and 115 kV Connection Facilities

A station capacity and voltage assessment was performed over the study period for the 230 kV and 115 kV TS's in the Region using the winter station peak load forecasts that were provided by the study team. The results are as follows:

6.4.1 Clarabelle TS

The 2019 actual non-coincident winter peak load at Clarabelle TS was 121 MW which is below the its 10-day winter LTR of 184 MW. Based on demand forecast Clarabelle TS will not be loaded above its 10-day LTR during the assessed planning horizon.

6.4.2 Elliot Lake TS

The 2019 actual non-coincident winter peak load on Elliot Lake TS was 20 MW which is below its 10-day winter LTR of 66 MW. Based on demand forecast, Elliot Lake TS will not be loaded above its 10-day LTR during the assessed planning horizon.

6.4.3 Espanola TS

The 2019 actual non-coincident winter peak for Espanola TS was 13 MW which is below the station 10-day winter LTR of 61 MW. As per the demand forecast, the loading at Espanola TS will not exceed the station 10-day winter LTR within the assessed planning horizon.

6.4.4 Larchwood TS

The 2019 actual non-coincident winter peak for Larchwood TS was 13 MW which is below the station 10-day winter LTR of 37 MW. Based on the submitted load forecast, the loading on Larchwoord TS will not exceed the station 10-day winter LTR within the assessed planning horizon.

6.4.5 Manitoulin TS

Manitoulin TS has a summer and winter 10-day LTR of 37 MW. The station loading - the weather adjusted winter peak loading of 37.8 MW - is already above the station LTR. The station supply capability is limited by a Current Transformer (CT) ratio setting on the low voltage bus of the station, thereby restricting the ability to utilize the full supply capability of the transformers. It should be noted

that the station low voltage bus configuration is such that the loss of one of the transformers will remove half of the load by configuration[4]. Therefore, the loss of one of the transformers during station peaking conditions will not result in a thermal overload of the remaining transformer. That being said, adequate supply capability at the station should be maintained to pick up the dropped load in the occurrence of such an event. Given its geographical location, this station cannot rely on any other nearby station for capacity relief via load transfer. Plans are already in place to address this need. These plans are further detailed in section 7 of this report.

IESO has expressed concerns on the voltage performance at the 115kV connection point of circuit S2B at Manitoulin TS. During system conditions where the nearby McCleans Mountain wind farm is unavailable, voltages on the 115kV side of the station can be as low as 108 kV which is below ORTAC voltage limit of 113kV. This low voltage incidence has previously been well documented and studied and was further reiterated in 2015 during the first cycle of the Sudbury/Algoma Needs Assessment. Circuit S2B is normally operated open, leaving Manitoulin TS, McCleans Mountain wind farm, one industrial customer and Whitefish DS on the Martindale TS side of the circuit. The low voltage at Manitoulin TS stems from the station being at the end of a long radial circuit under normal operating conditions. The power transformers at Manitoulin TS are equipped with under load tap changers with wide regulation bands (+/- 20%) to maintain the LV side voltage within acceptable voltage limits. As such, Hydro One is assured that the low voltage incidence at the Manitoulin TS high side connection point has no material impact on the system or its connected customers. Hydro One will continue to monitor the voltage performance at the Manitoulin TS high side connection point and will take the appropriate remedial actions if and when this low voltage incidence is deemed adversely impactive to customers and system reliability.

6.5 End-of-life (EOL) Equipment Needs

Hydro One and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next 10 years:

- Autotransformers
- Power transformers
- HV breakers
- Transmission line requiring refurbishment where an uprating is being considered for planning needs and require Leave to Construct (i.e., Section 92) application and approval
- HV underground cables where an uprating is being considered for planning needs and require EA and Leave to Construct (i.e., Section 92) application and approval

The end-of-life assessment for the above high voltage equipment typically included consideration of the following options:

[4] Discussion between the Transmitter and the LDC have confirmed that the existing configuration continues to provide an acceptable level of reliability.

1. Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement);
2. Replacing equipment with similar equipment of higher / lower ratings i.e. "right sizing" opportunity and built to current standards;
3. Replacing equipment with lower ratings and built to current standards by transferring some load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;

In addition, 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.

Accordingly, major high voltage equipment has been identified as approaching its end-of-life over the next 10 years and assessed for right sizing opportunity in section 7. At this time, end-of-life driven sustainement needs have been identified at the following stations in the region:

- Algoma TS,
- Clarabelle TS,
- Elliot Lake TS and
- Martindale TS

6.6 System Reliability and Load Restoration

In case of contingencies on the transmission system, ORTAC provides the load restoration requirements relative to the amount of load affected. Planned system configuration must not exceed 600 MW of load curtailment/rejection. In all other cases, the following restoration times are provided for load to be restored for the outages caused by design contingencies.

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

No new significant system reliability and operating issues were identified for the Sudbury/Algoma region.

The IESO has expressed the need for additional voltage control flexibility at Algoma TS and this is being addressed as part of the autotransformer replacement project planned at the station. The new autotransformers being procured are equipped with Under Load Tap Changers that will provide the required voltage control flexibility.

Based on the net coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW as per ORTAC. The maximum load interrupted by configuration due to the loss of two elements is below the ORTAC limit of 600MW by the end of the 10-year study period.

6.7 Longer Term Outlook (2029-2040)

Consistent with the NA, the RIP is based on on the 2020-2029 period, a further looking assessment was conducted and looked into the loading between 2029 and 2039. Appendix E presents the winter load forecast used for this assessement. The long-term load forecast was obtained from extrapolation of the near and medium term load forecast into 2039 using the station specific load growth factors.

No long-term needs for the Sudbury/Algoma region was identified beyond the already identified additional capacity needs at Manitoulin TS (starting 2020) and Martindale TS (starting 2028). Recommendations have been made and agreed upon by the Study Team on how to best address these needs. The study group recommend an on-going monitoring of additional load connection requests as they materialize themselves.

Municipalities in region may develop their community energy plans with a primary focus to reduce their energy consumption by local initiatives over next 25 to 30 years. With respect to electricity, these communities may plan for an increased reliance on community energy sources such as distributed generation, generation behind the meters like rooftop solar systems and local energy battery storage systems to reduce cost and for improved reliability of electricity supply.

Some of the communities in Ontario are working towards self-sufficiency by improving efficiencies of existing local energy systems i.e. reducing energy consumption and losses by means of utilizing smarter buildings, houses, efficient heating, cooling, appliances, equipment, and processes for all community needs. Ultimately, the objective of these energy plans in the region is to be a net zero carbon community over the next 25 to 30 years.

Community energy plans may have potential to supplement and/or defer future transmission infrastructure development needs. The Study Team therefore recommends LDCs to review their respective regional community energy plans and provide updates to the working group of any potential projects that may affect future load forecasts in the next cycle of regional planning.

7. REGIONAL NEEDS & PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IDENTIFIED IN THE PREVIOUS REGIONAL PLANNING CYCLE, THE NEEDS ASSESSMENT REPORT FOR THIS CYCLE; AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses infrastructure needs and plans to address these needs for the near-term (up to 5 years) and the mid- term (5 to 10 years) and the expected planned in service facilities to address these needs.

Current development and sustainment plans are further discussed below.

7.1 Martindale TS Supply Capacity

Martindale TS has a winter 10-day LTR of 164 MW. Based on current load growth projections at the station and considering expiration of generating contracts, the station net load will surpass the station winter 10-day LTR starting in 2028. This is the first iteration of the NA that shows a potential supply capacity need at the station. Given the anticipated timing of the need, there is time to re-evaluate this need in the next cycle of regional planning and once there is additional information on the IESO's resource adequacy framework, scheduled to take place no later than in 2025. Should the need materialize sooner than anticipated at Martindale TS, a station specific needs assessment can be carried out at that time so as to determine the best course of action for meeting the station supply capacity needs.

The following alternatives were considered to address the Martindale TS Supply Capacity need:

1. **Alternative 1 - Maintain Status Quo (Recommended)**: Martindale TS will exceed supply capacity in 2028 based on the load forecasts provided by area customers. The next cycle of regional planning will commence no later than in 2025 and will allow the working group to reevaluate this need and confirm whether or not the occurrence of the supply capacity congestion at Martindale still holds true in 2028. Should this be the case, the study group at that moment will decide the best course of actions to fill this need.

2. **Alternative 2– Add a low voltage capacitor bank for power factor correction:** Studies show that an additional 10 MW of supply capacity can be enabled by the the addition of a capacitor bank on the low voltage bus of this station. The addition of the capacitor bank will improve the station load power factor and draw less reactive power through the power transformers, enabling more active power flow on the units. This solution will provide capacity relief at Martindale TS beyond the study period and defer the need for additional transformation capacity. This alternative was considered but rejected due to how far in the future the need is ought to materialize itself. The next Regional Planning cycle of the region is to reevalute the station supply capacity needs and decide the optimal approach to address the need should it still exist.

7.2 Manitoulin TS Supply Capacity

Manitoulin TS has a summer and winter 10-day LTR of 37 MW. The station loading – the extreme weather adjusted winter peak loading of 37.8 MW - is already above the station LTR .The station supply capability is limited by a Current Transformer(CT) ratio setting on the low voltage bus of the station, thereby restricting the ability to utilize the full supply capability of the transformers. It should be noted that the station low voltage bus configuration is such that the loss of one of the transformers will remove half of the load by configuration[5]. That being said, adequate supply capability at the station should be maintained to pick up the dropped load in the occurrence of such an event. Given its geographical location, this station cannot rely on any other nearby station for capacity relief via load transfer. This need must be adressed as soon as practically feasible to allow full utilization of the station transformers capacity.

The following alternatives were considered to address the Manitoulin TS Supply Capacity need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected due to the fact that the station winter peak load is already above the station LTR. The absence of neighboring load supply stations that can provide capacity relief to Manitoulin TS should one of the power transformer be unavailable makes this alternative even more unacceptable.

2. **Alternative 2 - Change the CT ratio(Recommended):** A Preliminary assessement has identified that the existing limitation can be removed by changing the CT ratio. Hydro One Networks Inc. is coordinating the implementation of this alternative with the affected LDC. This alternative is currently planned to be implemented in 2021.

7.3 Martindale TS – Hanmer TS Corridor Unbundling

With either X25S or X26S is out of service, the loss of the companion circuit may result in voltage declines at Martindale 230kV and 115kV buses below acceptable ORTAC. The scope of this project aims to decouple one of the two circuits (X25S or X26S) into its own position at both Hanmer TS and Martindale TS. Hydro One Networks initiated this project as per the IESO's recommendation provided via a letter dated October 19th, 2018 addressed to Hydro One Transmission Planning Division. The targeted in service date is in year 2023.

7.4 Martindale TS EOL Autotransformer Replacement

Martindale TS is a 230/115kV BES classified station which also includes a 230kV/44kV Dual Element Spot Network (DESN) station located in Sudbury. The station is comprised of two (2) – 230/115 kV 125 MVA autotransformers (T21, T22) and one (1) 230/115 kV 115 MVA autotransformer (T23).

[5] Discussion between the Transmitter and the LDC have confirmed that the existing configuration continues to provide an acceptable level of reliability.

Autotransformers T21 and T23 as well as five (5) – 230kV breakers and select disconnect switches have been identified as EOL based on asset condition. Under peak load conditions, the loss of the two 125 MVA Martindale 230/115kV autransformers may result in the overload of the third smaller autransformer. The completion of this project will see the station equipped with three (3) 125MVA 230/115kV autotransformers.

The following alternatives where considered to remedie the T23 thermal overload and address EOL assets needs at Martindale TS:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition, would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with like for like replacement of the identifield EOL equipment within the station except for T23 where a larger unit matching the other two autotransformers is to be procured to replace the existing smaller unit. This alternative would address the end-of-life assets need and would alleviate the risk of overloading T23 should the other two larger transformer become simulatenously unavailable. This project is ongoing and planned to be in serviced in 2022.

7.5 Martindale TS EOL Power Transformer Replacement

Martindale TS, as mentioned above, also features a DESN station that supply both LDCs identified in the Sudbury/Algoma region. The DESN station is comprised of two(2) – 125 MVA 230/44kV power transformers. These power transformers as well as select 44 kV equipment are scheduled to be replaced in 2028 to address end-of-life needs. The identified EOL equipment will be replaced with Hydro One standard equipement of similar size and capabilities. These are the largest standard 230/44kV transformers Hydro One uses. The scope of this project as presently planned does not aim at increasing the Martindale TS supply capacity beyond what exists today nor does it deviate from Hydro One's standard transformer size and procurement practices.

The following alternatives were considered to address Martindale TS DESN station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with these end-of-life asset replacement as per the existing refurbishment plan for the EOL equipment at Martindale TS DESN. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

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7.6 Algoma TS EOL Autotransformer Replacement

Algoma TS is a BES autotransformation station located west of Sudbury in the Algoma area. The station serves at termination point to four (4) circuits – X27A, S22A and A23/24P – and features two 230/115kV autotransformers that supply the underlying 115kV transmission system. The autotransformer are respectively 195MVA (T5) and 115MVA (T6). The autotransformers are scheduled to be replaced with two 230/115kV 125 MVA units by the end of 2022. The new units are being procured with Under Load Tap Changers (ULTC) as a mean to provide better operational flexibility.

The following alternatives were considered to address Algoma TS station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 – Like-for-Like replacement with similar equipment**: This alternative was considered and rejected. The station supply need has been assessed and as a result, standard 125 MVA units are sufficient to adequately supply the forecasted region electricity need. Pursueing with this alternative will involve the procurement of two(2) non standard sized transformers and will continue to deviate Hydro One asset fleet with its standard equipement procurement standards.

3. **Alternative 3 – Like for like replacement with similar equipement and right sizing of T5 and T6 autotransformers (Recommended)**: Proceed with the end-of-life asset replacement and transformer right sizing plans as per the existing plans at Algoma TS. This alternative would address the end-of-life assets need, maintain reliable and adequate supply to the customers in the area while better aligning Hydro One asset fleet with its standard equipment procurement practices.

7.7 Clarabelle TS EOL Power Transformer Replacement

Clarabelle TS is a 230/44kV transformer station located in the Sudbury/Algoma region. The station features two 230/44kV 125 MVA step down transformers that supply both identified LDCs in the Sudbury/Algoma region. The power transformer at Clarabelle TS are scheduled to be replaced in 2027 alongside select station equipment to address EOL needs.
The following alternatives were considered to address Clarabelle TS station EOL assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

2. **Alternative 2 - Like-for-like replacement with similar equipment (Recommended):** Proceed with these end-of-life asset replacement as per the existing refurbishment plan for the power

transformers and identified EOL equipment at Clarabelle TS. This alternative would address the end-of-life assets need and would maintain reliable supply to the customers in the area.

7.8 Elliot Lake TS EOL Power Transformer Replacement

Elliot Lake TS is a Hydro One transformer station located west of Sudbury. The station consists of two(2) 115/44kV 42 MVA transformers (T1 and T3) alongside one 115kv/44kV 19 MVA transformer (T2). A station asset assessement has identified T1 and T2 as candidate for replacement within the mid-term horizon. Concurently, recent supply need assessement at the station has deemed T2 no longer necessary to maintain supply reliability and adequacy at the station. The LDC supplied from Elliot Lake TS further concurred that T2 can be removed from Elliot Lake TS without impacting their supply reliability and adequacy . As such, this project will see the like-for-like replacement of T1 transformer, the removal of T2 transformer and the reconfiguration of the station to a near standard Jones DESN design.

The following alternatives were considered to address Elliot Lake TS station EOL assets need:

4. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and will not meet Hydro One's obligation to provide reliable supply to the customers.

5. **Alternative 2 – Like-for-Like replacement with similar equipment**: This alternative was considered and rejected. The station supply need has been assessed and as a result, T2 transformer was deemed no longer necessary. Pursueing with this alternative will involve the procurement of an additional transformer that is no longer needed in addition of continueing to maintain non standard station configuration.

6. **Alternative 3 - Like for like replacement with similar equipement and removal of T2(Recommended)**: Proceed with the end-of-life asset replacement and station reconfiguration plans as per the existing station refurbishement and reconfiguration plans at Elliot Lake TS. This alternative would address the end-of-life assets need, maintain reliable supply to the customers in the area while avoiding the need to procure and maintain an asset that is deemed no longer necessary.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN (RIP) REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SUDBURY/ALGOMA REGION.

The Study Team reaffirms the recommendations from NA to the continue with infrastructure investments presented in section 7. Hydro One and the affected LDCs are to jointly coordinate the implementation of these undertakings while keeping the Study Team apprised of project status. Below is a summary of the near and mid-term planned projects along with their respective planned in service dates and planning allowances:

1. Hanmner TS to Martindale TS corridor Unbundling – Estimated at $8M and planned to be in service in 2023,
2. Martindale TS autotransformer replacement - Estimated at $76M and planned to be in service in 2022
3. Martindale TS EOL Power transformer replacement – Estimated at $19M and planned to be in service in 2028
4. Manitoulin TS supply capacity – Estimated at $20,000 and planned to be in serviced in 2021
5. Algoma TS EOL autotransformer replacement – Estimated at $23M and planned to be in service in 2023
6. Clarabelle TS EOL Power transformer replacement – Estimated at $19M and planned to be in service in 2027
7. Elliot Lake TS EOL Power transformer replacement – Estimated at $23M and planned to be in service in 2025

9. REFERENCES

[1]. Hydro One, "Needs Assessment Report, Sudbury/Algoma region", 6 August 2020

[2]. Regional Infrastructure Planning Report 2016 – Sudbury/Algoma - June 2016

[3]. Needs Assessment Report Sudbury/Algoma – March 2015

[4]. Planning Process Working Group Report to the Ontario Energy Board - May 2013

[5]. Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 -August 2007

Appendix A: Transmission Lines in the Sudbury/Algoma Region

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	X74P	Hanmer TS	Mississagi TS	230
2.	X27A	Hanmer TS	Algoma TS	230
3.	A23P, A24P	Algoma TS	Mississagi TS	230
4.	X23N	Hamner TS	-	230
5.	S21N	Martindale TS	-	230
6.	X25S, X26S	Hanmer TS	Martindale TS	230
7.	S22A	Martindale TS	Algoma TS	230
8.	S6F	Martindale TS	-	115
8.	S5M	Martindale TS	Larchwood TS	115
9.	S2B	Martindale TS	Algoma TS	115
10.	B4B	Algoma TS	B3E Tap	115
11.	T1B	Algoma TS	-	115
12.	B3E	B4B Tap	Elliot Lake TS	115
13.	B4E	B4B Tap	Elliot Lake TS	115
14.	L1S	Martindale TS	Crystal Falls TS	115

Appendix B: Lists of Autotransformer and Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)
1.	Algoma TS	230/115
2.	Coniston TS	115/22
3.	Clarabelle TS	230/44
4.	Elliot Lake TS	115/44
5.	Espanola TS	115/44
6.	Hamner TS	500/230
7.	Larchwood TS	115/44
8.	Manitoulin TS	115/44
9.	Martindale TS	230/115 230/44

Appendix D: Lists of LDCs in the Sudbury/Algoma region

Sr. No.	Company	Connection Type (TX/DX)
1.	Greater Sudbury Hydro	TX / DX
2.	Hydro One Distribution	TX
3.	North Bay Hydro	DX

Appendix D: Extreme Weather Adjusted Non-Coincident Winter Load Forecast

Table D.1: Sudbury/Algoma region Winter Non-Coincident Load Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Load Growth Factor	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment									
						2019	WAN	WAE		Near Term Forecast (MW)					Medium Term Forecast (MW)				
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Clarabelle TS	*T1/T2*	204.8	184.32	N	H1Dx Gross Peak				1.07%	47.19	47.64	48.08	48.53	48.98	49.43	49.88	50.32	50.77	51.22
					GSH Gross Peak				0.81%	83.67	84.28	84.89	85.50	86.11	86.72	87.33	87.94	88.55	89.16
					Station Gross Peak					130.86	131.92	132.97	134.03	135.09	136.15	137.20	138.26	139.32	140.38
					DG					6.70	6.70	6.70	6.70	6.70	6.70	0.00	0.00	0.00	0.00
					CDM					0.48	0.50	0.51	0.53	0.55	0.56	0.58	0.60	0.62	0.63
					Station Net Peak	121.19	123.10	130.37		123.68	124.72	125.76	126.80	127.84	128.88	136.62	137.66	138.70	139.74
Elliot Lake TS	*T1/T2/T3*	73.8	66.42	N	Gross Peak				0.67%	20.02	20.15	20.27	20.40	20.52	20.65	20.77	20.90	21.02	21.15
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.08	0.08	0.08	0.08	0.09	0.09	0.09	0.09	0.10	0.10
					Station Net Peak	19.59	19.90	21.07		19.94	20.23	20.35	20.48	20.61	20.74	20.86	20.99	21.12	21.25
Espanola TS	*T1/T2/T3*	64.4	61.18	Y	Gross Peak				0.65%	13.06	13.14	13.21	13.29	13.37	13.45	13.53	13.61	13.69	13.77
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.06	0.06
					Station Net Peak	12.78	12.98	13.74		13.01	13.08	13.16	13.24	13.32	13.39	13.47	13.55	13.63	13.70
Larchwood TS	*T2*	41.7	37.53	N	Gross Peak				1.02%	13.11	13.24	13.37	13.49	13.62	13.74	13.87	13.99	14.12	14.25
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07
					Station Net Peak	12.79	12.99	13.76		13.06	13.19	13.31	13.44	13.56	13.68	13.81	13.93	14.05	14.18
Manitoulin TS	*T3/T4*	41.7	37.53	N	Gross Peak				1.08%	40.21	40.59	40.98	41.37	41.75	42.14	42.52	42.91	43.30	43.68
					DG					2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01	2.01
					CDM					0.15	0.15	0.16	0.16	0.17	0.17	0.18	0.19	0.19	0.20
					Station Net Peak	37.22	37.81	40.04		38.05	38.43	38.81	39.19	39.58	39.96	40.34	40.72	41.10	41.48

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Load Growth Factor	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment									
						2019	WAN	WAE		Near Term Forecast (MW)					Medium Term Forecast (MW)				
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Martindale TS	*T25/T26*	182.6	164.34	N	H1Dx Gross Peak				0.06%	53.33	53.36	53.38	53.41	53.44	53.47	53.50	53.52	53.55	53.58
					GSH Gross Peak				2.15%	97.54	99.49	101.44	103.39	105.34	107.29	109.25	111.20	113.15	115.10
					Station Gross Peak					150.86	152.84	154.82	156.80	158.78	160.76	162.74	164.72	166.70	168.68
					DG					7.49	7.49	7.49	7.49	7.49	2.49	2.49	0.89	0.89	0.89
					CDM					0.57	0.58	0.61	0.64	0.68	0.70	0.72	0.73	0.75	0.77
					Station Net Peak	139.19	141.39	149.75		142.80	144.77	146.73	148.67	150.62	157.58	159.53	163.10	165.06	167.02
Massey DS	*T1*	N/A	N/A	N/A	Gross Peak	6.81	6.92	7.33	0.57%	6.95	6.99	7.03	7.07	7.10	7.14	7.18	7.22	7.25	7.29
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	6.81	6.92	7.33		6.93	6.96	7.00	7.04	7.07	7.11	7.15	7.18	7.22	7.26
North Shore DS	*T1*	N/A	N/A	N/A	Gross Peak				1.06%	5.75	5.81	5.87	5.93	5.98	6.04	6.10	6.15	6.21	6.27
					DG					2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59	2.59
					CDM					0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.61	5.70	6.03		3.14	3.20	3.25	3.31	3.36	3.42	3.48	3.53	3.59	3.65
Sowerby DS	*T1*	N/A	N/A	N/A	Gross Peak				0.81%	4.96	5.00	5.04	5.08	5.12	5.15	5.19	5.23	5.27	5.31
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03
					Station Net Peak	4.85	4.93	5.22		4.95	4.98	5.02	5.06	5.09	5.13	5.17	5.21	5.24	5.28
Spanish DS	*T1*	N/A	N/A	N/A	Gross Peak				0.88%	3.94	3.97	4.00	4.03	4.07	4.10	4.13	4.17	4.20	4.23
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
					Station Net Peak	3.84	3.90	4.13		3.92	3.95	3.99	4.02	4.05	4.08	4.11	4.15	4.18	4.21
Striker DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.79%	7.83	7.89	7.95	8.01	8.06	8.12	8.18	8.24	8.29	8.35
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
					Station Net Peak	7.65	7.77	8.23		7.80	7.86	7.92	7.97	8.03	8.09	8.14	8.20	8.26	8.31

Transformer Station Name	DESN ID (e.g. T1/T2)	LTR (MVA)	LTR (MW)	LV Cap Bank	Historical Data (MW)				Load Growth Factor	Winter Peak Load (MW) - Linearized Load Forecast - Data to be used in the Needs Assessment									
						2019	WAN	WAE		Near Term Forecast (MW)					Medium Term Forecast (MW)				
					Customer Data	1	1.0158	1.0758		2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Verner DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.69%	6.10	6.14	6.18	6.22	6.26	6.30	6.34	6.38	6.42	6.46
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.97	6.06	6.42		6.08	6.12	6.16	6.20	6.24	6.27	6.31	6.35	6.39	6.43
Warren DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				0.78%	7.61	7.67	7.72	7.78	7.83	7.89	7.95	8.00	8.06	8.11
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04
					Station Net Peak	7.44	7.55	8.00		7.58	7.64	7.69	7.75	7.80	7.86	7.91	7.97	8.02	8.08
Wharncliffe DS	*T1/T2*	N/A	N/A	N/A	Gross Peak				1.30%	5.52	5.59	5.66	5.72	5.79	5.86	5.93	5.99	6.06	6.13
					DG					0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42	0.42
					CDM					0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	5.37	5.45	5.78		5.08	5.15	5.22	5.28	5.35	5.42	5.48	5.55	5.62	5.68
Whitefish DS	*T1*	N/A	N/A	N/A	Gross Peak				0.67%	6.65	6.69	6.74	6.78	6.82	6.86	6.90	6.94	6.99	7.03
					DG					0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
					CDM					0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
					Station Net Peak	6.51	6.61	7.00		6.6	6.67	6.71	6.75	6.79	6.83	6.87	6.91	6.95	6.99

Appendix E: Long-term Winter Load Forecast

Table E.1: Sudbury/Algoma region Winter Non-Coincident Load Forecast

Transformer Station Name	DESN ID (e.g. T1/T2)	Station winter LTR (MVA)	Station Winter LTR (MW)	Winter Peak Load - Linearized Load Forecast - Extended to Long-term Forecast											
				Near Term Forecast (MW)					Medium Term Forecast (MW)					Long-term Forecast	
				2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2034	2039
Clarabelle TS	T1/T2	204.8	184.32	123.68	124.72	125.76	126.80	127.84	128.88	136.62	137.66	138.70	139.74	146.68	151.50
Elliot Lake TS	T1/T2/T3	73.8	66.42	19.94	20.23	20.35	20.48	20.61	20.74	20.86	20.99	21.12	21.25	22.11	22.70
Espanola TS	T1/T2/T3	64.4	61.18	13.01	13.08	13.16	13.24	13.32	13.39	13.47	13.55	13.63	13.70	14.24	14.61
Larchwood TS	T2	41.7	37.53	13.06	13.19	13.31	13.44	13.56	13.68	13.81	13.93	14.05	14.18	15.07	15.70
Manitoulin TS	T3/T4	41.7	37.53	38.05	38.43	38.81	39.19	39.58	39.96	40.34	40.72	41.10	41.48	44.23	46.17
Martindale TS	T25/T26	182.6	164.34	142.80	144.77	146.73	148.67	150.62	157.58	159.53	163.10	165.06	167.02	180.71	190.46
Massey DS	T1	N/A	N/A	6.93	6.96	7.00	7.04	7.07	7.11	7.15	7.18	7.22	7.26	7.51	7.68
North Shore DS	T1	N/A	N/A	3.14	3.20	3.25	3.31	3.36	3.42	3.48	3.53	3.59	3.65	3.88	4.05
Sowerby DS	T1	N/A	N/A	4.95	4.98	5.02	5.06	5.09	5.13	5.17	5.21	5.24	5.28	5.54	5.72
Spanish DS	T1	N/A	N/A	3.92	3.95	3.99	4.02	4.05	4.08	4.11	4.15	4.18	4.21	4.44	4.60
Striker DS	T1/T2	N/A	N/A	7.80	7.86	7.92	7.97	8.03	8.09	8.14	8.20	8.26	8.31	8.71	8.99
Verner DS	T1/T2	N/A	N/A	6.08	6.12	6.16	6.20	6.24	6.27	6.31	6.35	6.39	6.43	6.70	6.89
Warren DS	T1/T2	N/A	N/A	7.58	7.64	7.69	7.75	7.80	7.86	7.91	7.97	8.02	8.08	8.46	8.73
Wharncliffe DS	T1/T2	N/A	N/A	5.08	5.15	5.22	5.28	5.35	5.42	5.48	5.55	5.62	5.68	6.14	6.46
Whitefish DS	T1	N/A	N/A	6.63	6.67	6.71	6.75	6.79	6.83	6.87	6.91	6.95	6.99	7.28	7.48
			Region Total	402.65	406.95	411.07	415.19	419.30	428.44	439.26	444.99	449.13	453.25	481.71	501.74

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
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
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station