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July 26th, 2017

Josh Smith
Electrical Distribution and Planning Engineer
Erie Thames Power Lines Corporation
143 Bell Street,
PO Box 157
Ingersoll, ON, N5C 3K5

Dear Mr. Smith,

Subject: Regional Planning Status

This letter is in response to your request for a Planning Status letter for your cost of service application. The province has been divided into 21 Regions for the purpose of regional planning, which are assigned to one of the 3 Groups to prioritize and manage the regional planning process. A map showing details with respect to the 21 Regions and the list of LDCs in each Region are attached in Appendix A and B respectively.

Erie Thames Power Lines Corporation belongs to London Area (Group 2 Region) and Greater Bruce/Huron Area (Group 3 Region), in which Hydro One Networks Inc. (HONI) is the lead transmitter.

This letter confirms that the first cycle of regional planning process for both Regions is currently underway and is anticipated to complete by August 2017. An overview of Ontario's regional planning process is available on Hydro One's Regional Planning homepage. Each region's current status and corresponding reports are also published online and can be accessed using the links above. The planning statuses for the two regions of your interest are briefly discussed below.

London Area Region
This region has been divided into 5 sub-regions; Strathroy, Greater London, Woodstock, St. Thomas, and Aylmer-Tillsonburg. Needs Assessment (NA) Report (Appendix C) for London area was completed on April 2, 2015 and Scoping Assessment was completed on August 28, 2015. The Local Planning (LP) Reports (Appendix C) for Strathroy TS and Woodstock Sub-region Restoration were completed in September 2016 and May 2017, respectively.

The Working Group recommended that Integrated Regional Resource Plan (IRRP) was only required for Greater London Sub-Region, which was completed in January this year and is available at IRRP. Regional Infrastructure Planning (RIP) phase for this region is currently underway and anticipated to complete by August 2017.

The IRRP recommends installation of switching devices and feeder extensions for a total cost of $1.8M to address the restoration issues in the London sub region and there is no cost implication for Erie Thames Power Lines Corporation.

There are couple end-of-life asset refurbishments and few development projects in the region underway and/or planned over the next few years. It is expected that there will be little or no cost implications for Erie Thames Power Lines Corporation from these projects. However, if any, it will be incorporated into the Region's RIP report.

Greater Bruce / Huron Area

The NA for the Greater Bruce/Huron region was completed in May 2016 (Appendix D). The Working Group recommended the following needs to be addressed:

- Low power factor at Wingham TS (and resulting voltage deficiency) and Bruce HW Plant B TS
- Thermal overloading on the 115 kV circuit L7S
- Customer Delivery Point Performance

The Working Group concluded that no further regional coordination was required and the plans to mitigate the above needs will be developed via the Local Planning process and Hydro One's OEB-approved process for addressing delivery point performance. Local planning was completed for these needs. Local Planning reports (Appendix D) were developed for needs at Wingham TS, L7S circuit capacity and Bruce HWP B TS. It is expected that that there will be little or no cost implications for Erie Thames Power Lines Corporation. The RIP report for Greater Bruce/Huron Region is expected to be completed in August 2017.

Erie Thames Power Lines Corporation is an active participating member of the Working Group. Further details will be discussed with the Working Group Members and communicated as they become available. Hydro One looks forward to working with Erie Thames Power Lines Corporation in executing the regional planning process.

Please feel free to contact me if you have any questions.

Sincerely,

Ajay Garg, Manager - Regional Planning Coordination
Hydro One Networks Inc.

Appendix A: Map of Ontario's Planning Regions

Northern Ontario

Southern Ontario

Greater Toronto Area (GTA)

Group 1	Group 2	Group 3
Burlington to Nanticoke	East Lake Superior	Chatham/Lambton/Sarnia
Greater Ottawa	London area	Greater Bruce/Huron
GTA East	Peterborough to Kingston	Niagara
GTA North	South Georgian Bay/Muskoka	North of Moosonee
GTA West	Sudbury/Algoma	North/East of Sudbury
Kitchener- Waterloo- Cambridge-Guelph ("KWCG")		Renfrew
Metro Toronto		St. Lawrence
Northwest Ontario		
Windsor-Essex		

Appendix B: List of LDCs for Each Region

[Hydro One as Upstream Transmitter]

Region	LDCs
1. Burlington to Nanticoke	• Energy+ Inc. (formerly Brant County Power Inc.) • Brantford Power Inc. • Burlington Hydro Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Norfolk Power Distribution Inc.** • Oakville Hydro Electricity Distribution Inc.
2. Greater Ottawa	• Hydro 2000 Inc. • Hydro Hawkesbury Inc. • Hydro One Networks Inc. • Hydro Ottawa Limited • Ottawa River Power Corporation • Renfrew Hydro Inc.
3. GTA North	• Enersource Hydro Mississauga Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Newmarket-Tay Power Distribution Ltd. • PowerStream Inc. • PowerStream Inc. [Barrie] • Toronto Hydro Electric System Limited • Veridian Connections Inc.
4. GTA West	• Burlington Hydro Inc. • Enersource Hydro Mississauga Inc. • Halton Hills Hydro Inc. • Hydro One Brampton Networks Inc. • Hydro One Networks Inc. • Milton Hydro Distribution Inc. • Oakville Hydro Electricity Distribution Inc.

5. Kitchener- Waterloo-Cambridge-Guelph (“KWCG”)	• Energy+ Inc. (formerly Cambridge and North Dumfries Hydro Inc.) • Centre Wellington Hydro Ltd. • Guelph Hydro Electric System - Rockwood Division • Guelph Hydro Electric Systems Inc. • Halton Hills Hydro Inc. • Hydro One Networks Inc. • Kitchener-Wilmot Hydro Inc. • Milton Hydro Distribution Inc. • Waterloo North Hydro Inc. • Wellington North Power Inc.
6. Metro Toronto	• Enersource Hydro Mississauga Inc. • Hydro One Networks Inc. • PowerStream Inc. • Toronto Hydro Electric System Limited • Veridian Connections Inc.
7. Northwest Ontario	• Atikokan Hydro Inc. • Chapleau Public Utilities Corporation • Fort Frances Power Corporation • Hydro One Networks Inc. • Kenora Hydro Electric Corporation Ltd. • Sioux Lookout Hydro Inc. • Thunder Bay Hydro Electricity Distribution Inc.
8. Windsor-Essex	• E.L.K. Energy Inc. • Entegrus Power Lines Inc. [Chatham- Kent] • EnWin Utilities Ltd. • Essex Powerlines Corporation • Hydro One Networks Inc.
9. East Lake Superior	N/A → This region is not within Hydro One’s territory
10. GTA East	• Hydro One Networks Inc. • Oshawa PUC Networks Inc. • Veridian Connections Inc. • Whitby Hydro Electric Corporation

11. London area	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Hydro One Networks Inc. • London Hydro Inc. • Norfolk Power Distribution Inc.** • St. Thomas Energy Inc. • Tillsonburg Hydro Inc. • Woodstock Hydro Services Inc.**
12. Peterborough to Kingston	• Eastern Ontario Power Inc. • Hydro One Networks Inc. • Kingston Hydro Corporation • Lakefront Utilities Inc. • Peterborough Distribution Inc. • Veridian Connections Inc.
13. South Georgian Bay/Muskoka	• Collingwood PowerStream Utility Services Corp. (COLLUS PowerStream Corp.) • Hydro One Networks Inc. • Innisfil Hydro Distribution Systems Limited • Lakeland Power Distribution Ltd. • Midland Power Utility Corporation • Orangeville Hydro Limited • Orillia Power Distribution Corporation • Parry Sound Power Corp. • Powerstream Inc. [Barrie] • Tay Power • Veridian Connections Inc. • Veridian-Gravenhurst Hydro Electric Inc. • Wasaga Distribution Inc.
14. Sudbury/Algoma	• Espanola Regional Hydro Distribution Corp. • Greater Sudbury Hydro Inc. • Hydro One Networks Inc.
15. Chatham/Lambton/Sarnia	• Bluewater Power Distribution Corporation • Entegrus Power Lines Inc. [Chatham- Kent] • Hydro One Networks Inc.
16. Greater Bruce/Huron	• Entegrus Power Lines Inc. [Middlesex] • Erie Thames Power Lines Corporation • Festival Hydro Inc. • Hydro One Networks Inc. • Wellington North Power Inc. • West Coast Huron Energy Inc. • Westario Power Inc.

17. Niagara	• Canadian Niagara Power Inc. [Port Colborne] • Grimsby Power Inc. • Haldimand County Hydro Inc.** • Horizon Utilities Corporation • Hydro One Networks Inc. • Niagara Peninsula Energy Inc. • Niagara-On-The-Lake Hydro Inc. • Welland Hydro-Electric System Corp. • Niagara West Transformation Corporation* * Changes to the May 17, 2013 OEB Planning Process Working Group Report
18. North of Moosonee	N/A → This region is not within Hydro One's territory
19. North/East of Sudbury	• Greater Sudbury Hydro Inc. • Hearst Power Distribution Company Limited • Hydro One Networks Inc. • North Bay Hydro Distribution Ltd. • Northern Ontario Wires Inc.
20. Renfrew	• Hydro One Networks Inc. • Ottawa River Power Corporation • Renfrew Hydro Inc.
21. St. Lawrence	• Cooperative Hydro Embrun Inc. • Hydro One Networks Inc. • Rideau St. Lawrence Distribution Inc.

**This Local Distribution Company (LDC) has been acquired by Hydro One Networks Inc. Please refer to the letter for a brief description on the acquisition approved by the Ontario Energy Board (OEB).

Appendix C

1) Needs Assessment Report – London Area
2) Local Planning Report – Strathroy TS
3) Local Planning Report – Woodstock TS Restoration

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

NEEDS ASSESSMENT REPORT

Region: London

Date: April 1, 2015

Prepared by: London Area Study Team

London Area Study Team	
Organization	**Name**
Hydro One Networks Inc. (Lead Transmitter)	Kennan Ip Jennifer Li Raymond Zeng
Independent Electricity System Operator	Phillip Woo Kun Xiong Jiya Shoaib
Entegrus Power Lines	Matthew Meloche
Erie Thames Power Lines Corporation	Chuck deJong Josh Smith Tim Collins
London Hydro Inc.	Bill Milroy Ismail Sheikh
St. Thomas Energy Inc.	Larry Martin
Tillsonburg Hydro Inc.	Stephen Gradish
Woodstock Hydro Services Inc.	Jay Heaman
Hydro One Networks Inc. (Distribution)	Alexander Hamlyn

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the London Area and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

Study team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the Needs Assessment Report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the Needs Assessment Report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	London Area		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	February 2, 2015	**END DATE**	April 3, 2015

1. INTRODUCTION

The purpose of this Needs Assessment (NA) report is to undertake an assessment of the London Area and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE / TRIGGER

The NA for the London Area was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is completed and has been initiated for Group 2 Regions. The London Area belongs to Group 2. The NA for the London Area was triggered on January 30, 2015 and was completed on March 31, 2015.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the NA study was conducted for the next 10 years as per the recommendations of the Planning Process Working Group (PPWG) Report to the Board. As such, relevant data and information was collected up to the year 2023.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led SA, which will determine the appropriate regional planning approach: IRRP, RIP, and/or local planning.

This NA included a review of transmission system connection facilities capability, which covers station and line loading, thermal and voltage analysis as well as a review of system reliability, operational issues such as load restoration, and assets approaching end-of-useful-life.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One Transmission provided information for the London Area. The information included: historical load, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, load restoration data, and performance information including major equipment approaching end-of-useful life. In this region, asset utilization is at the capacity threshold even when LDCs CDM forecast is taken into account. Accordingly, further assessment is required to determine possible targeted CDM activities by feeders and station(s) to ensure CDM will meet load reduction forecasts. See Section 4 for further details.

5. NEEDS ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the London Area over the study period (2014 to 2023). The assessment reviewed available information and load forecasts and included single contingency analysis to confirm needs, if and when required. See Section 5 for further details.

6. RESULTS

Transmission Capacity Needs

A. 230/115 kV Autotransformers

- The 230/115 kV autotransformers (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

B. 230 kV Transmission Lines

- The 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit.
- Under high eastwardly flows and or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

C. 115kV Transmission Lines

- The 115 kV circuit W8T reaches its continuous rating pre-contingency in 2014 based on the gross load forecast.
- The remaining 115 kV circuits supplying the London Area are adequate over the study period for the loss of a single 115 kV circuit.

D. 230 kV and 115 kV Connection Facilities

- Loadings at Aylmer TS, Strathroy TS and Wonderland TS exceed their transformer 10-Day Long Term Rating (LTR) in 2014 based on the net load forecast. The limitation at Aylmer TS will be addressed through the currently planned sustainment investment. Tillsonburg TS is forecasted to exceed its 10-Day LTR by the end of near term. Clarke TS is forecasted to exceed its 10-Day LTR in 2014 based on the gross load forecast, but is expected to be adequate to meet the net load forecast for the remainder of the study as planned CDM targets and DG contributions continue to offset the load growth.
- Historical data shows that Buchanan DESN power factor may be below Ontario Resource and Transmission Assessment Criteria under peak load conditions.

System Reliability, Operation and Restoration Review

Based on the net and gross load forecast, the 115 kV voltages at Tillsonburg TS were found to be less than minimum requirements under pre-contingency conditions in the near term.

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

For the loss of two elements on the 230kV system, the gross and net load interrupted by configuration at peak conditions will exceed 150 MW and 250 MW.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

Aging Infrastructure / Replacement Plan

During the study period, plans to replace or add equipment do not affect the needs identified.

7. RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends that:

a) The following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or wires planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

b) No further regional coordination is required and following needs should be further assessed as part of local planning :

- Low power factor at Buchanan DESN

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1 INTRODUCTION

This Needs Assessment (NA) report provides a summary of needs that are emerging in the London Area between 2014 – 2023. The development of the NA report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the "Planning Process Working Group (PPWG) Report to the Board".

The purpose of this NA is to undertake an assessment of the London Area to identify any near term and/or emerging needs in the area and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with Local Distribution Companies (LDC) or other connecting customer(s), will further undertake planning assessments to develop options and recommend a solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment (SA) process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required. The SA may also recommend that local planning between the transmitter and affected LDCs be undertaken to address certain needs.

This report was prepared by the London Area NA study team (Table 1) and led by the transmitter, Hydro One Networks Inc. The report captures the results of the assessment based on information provided by LDCs, and the IESO.

Table 1: Study Team Participants for London Area

No.	Company
1.	Hydro One Networks Inc. (Lead Transmitter, "Hydro One Transmission")
3.	Independent Electricity System Operator ("IESO")
4.	Entegrus Power Lines lnc.
5.	Erie Thames Power Lines Corporation
6.	London Hydro Inc.
7.	St. Thomas Energy Inc.
8.	Tillsonburg Hydro Inc.
9.	Woodstock Hydro Services Inc.
10.	Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE / TRIGGER

The NA for the London Area was triggered in response to the OEB's Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups. The NA for Group 1 Regions is complete and has been initiated for Group 2 Regions. The London Area belongs to Group 2. The NA for this area was triggered on January 30, 2015 and was completed on March 31, 2015.

3 SCOPE OF NEEDS ASSESSMENT

This NA covers the London Area over an assessment period of 2014 to 2023. The scope of the NA includes a review of transmission system connection facility capability which covers transformer station and line thermal capacity and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this NA.

3.1 London Area Description and Connection Configuration

The London Area includes the municipalities of Oxford County (comprising Township of Blandford-Blenheim, Township of East Zorra-Tavistock, Town of Ingersoll, Township of Norwich, Township of South-West Oxford, Town of Tillsonburg, Township of Zorra), City of Woodstock, Middlesex County (comprising Municipality of Adelaide Metcalfe , Municipality of Lucan Biddulph, Municipality of Middlesex Centre, Municipality of North Middlesex, Municipality of Southwest Middlesex, Municipality of Strathroy-Caradoc, Municipality of Thames Centre, Village of Newbury), City of London, Elgin County (comprising Municipality of Town of Aylmer, Municipality of Bayham, Municipality of Central Elgin, Municipality of West Elgin, Municipality of Dutton/Dunwich, Township of Malahide, Township of Southwold), City of St. Thomas. In addition, the facilities located in the London Region supply part of Norfolk County. The boundaries of the London Area are shown below in Figure 1.

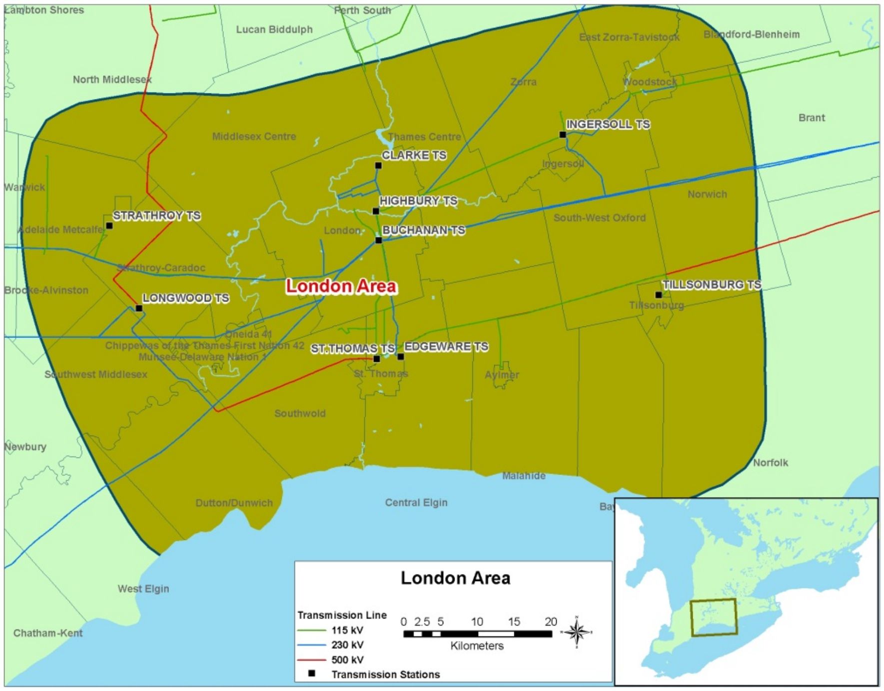

Figure 1: London Area Map

Electrical supply to the London Area is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Longwood Transformer Station (TS) and 230/115 kV autotransformers at Buchanan TS and Karn TS. There are fourteen Hydro One step-down TS's, four direct transmission connected load customers and three transmission connected generators in the London Area. The distribution system consists of voltage levels 27.6 kV and 4.16kV.

The existing facilities in the London Area are summarized below and depicted in the single line diagram shown in Figure 2. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment. Also, although depicted, Duart TS is not included in the London Area study and will be studied as part of the Chatham Area Regional Infrastructure Plan.

- Longwood TS is the major transmission station that connects the 500kV network to the 230kV system via two 500/230 kV autotransformers.
- Buchanan TS and Karn TS are the transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Fourteen step-down transformer stations supply the London Area load: Aylmer TS, Buchanan TS, Clarke TS, Commerceway TS, Edgeware TS, Highbury TS, Ingersoll

TS, Nelson TS, Strathroy TS, St. Thomas TS, Talbot TS, Tillsonburg TS, Wonderland TS, and Woodstock TS.

- Four Customer Transformer Stations (CTS) are supplied in the London Area: Ford Talbotville CTS, Enbridge Keyser CTS, Lafarge Woodstock CTS, and Toyota Woodstock CTS.

- There are 3 existing Transmission connected generating stations in the London Area as follows:
    - Suncor Adelaide GS is a 40 MW wind farm connected to 115 kV circuit west of Strathroy TS
    - Port Burwell GS is a 99 MW wind farm connected to 115kV circuit near Tillsonburg TS
    - Silver Creek GS is a 10 MW solar generator connected to 115kV circuit near Aylmer TS

- There are a network of 230 kV and 115 kV circuits that provide supply to the London Area, as shown in Table 2 below:

Table 2: Transmission Lines in London Area

Voltage	Circuit Designations	Location
230 kV	N21W, N22W	Scott TS to Buchanan TS
	W42L, W43L	Longwood TS to Buchanan TS
	W44LC	Longwood TS to Chatham TS to Buchanan TS
	W45LS	Longwood TS to Spence SS to Buchanan TS
	W36, W37	Buchanan TS to Talbot TS
	D4W, D5W	Buchanan TS to Detweiler TS
	M31W, M32W	Buchanan TS to Ingersoll TS to Middleport TS
	M33W	Buchanan TS to Brantford TS
115 kV	W2S	Buchanan TS to Strathroy TS
	W5N	Buchanan TS to Nelson TS
	W6NL	Buchanan TS to Highbury TS to Nelson TS
	W9L	Buchanan TS to Highbury TS
	W7, W12 WW1C W8T WT1T W3T, W4T WT1A K7, K12	Buchanan TS to CTS Buchanan TS to CTS Buchanan TS to ESWF JCT ESWF JCT to Tillsonburg TS Buchanan TS to St. Thomas TS Aylmer TS to Lyons JCT Karn TS to Commerce Way TS

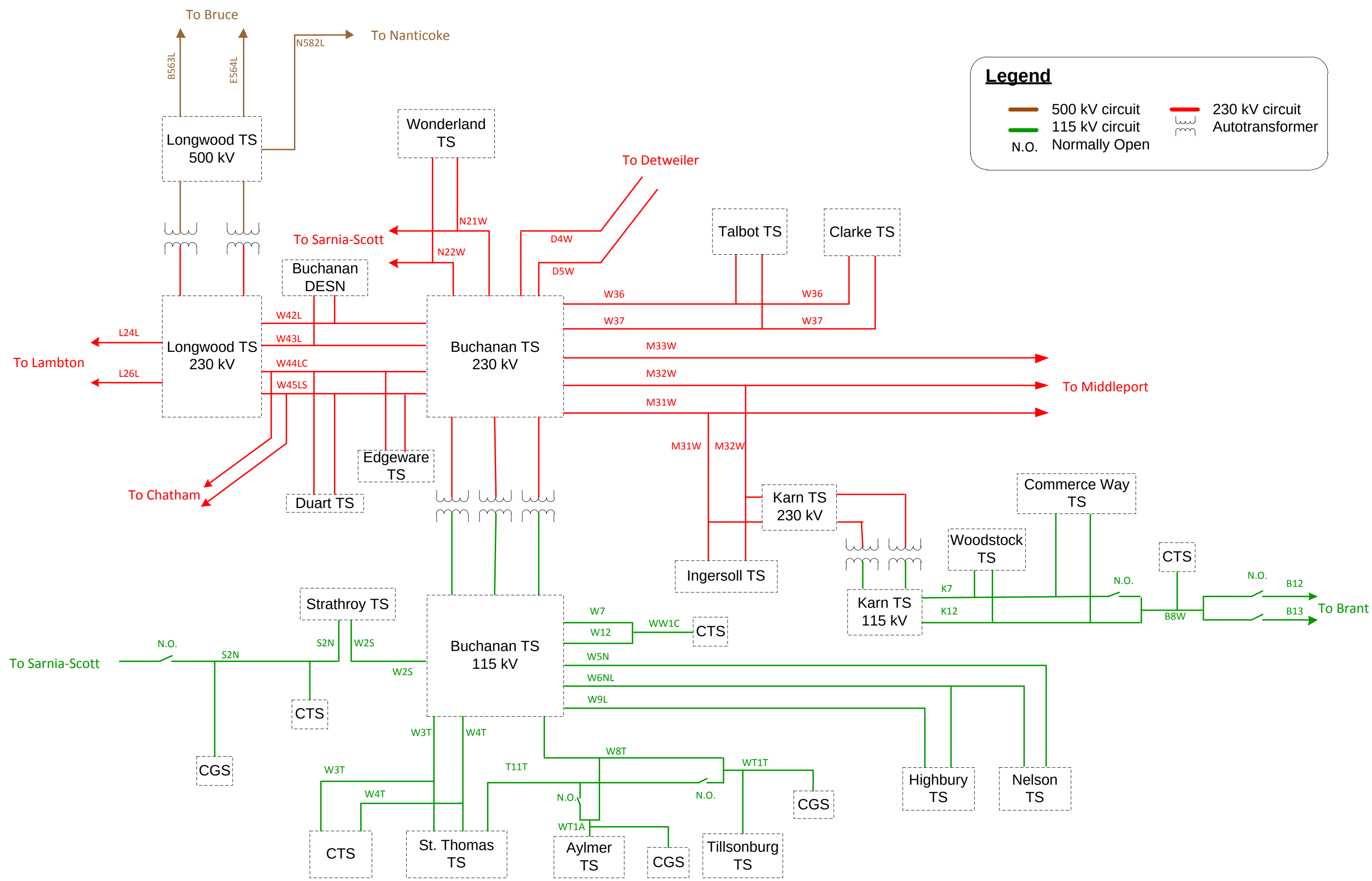

Figure 2: Single Line Diagram – London Area

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information and data to Hydro One:

- IESO provided:
  i. Historical 2013 regional coincident peak load and station non-coincident peak load
  ii. List of existing reliability and operational issues
  iii. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
- LDCs provided historical (2011-2013) net load, and gross load forecast (2014-2023)
- Hydro One (Transmission) provided transformer, station, and circuit ratings
- Any relevant planning information, including planned transmission and distribution investments provided by the transmitter and LDCs, etc.

4.1 Gross Load Forecast

The gross load forecast describes the total forecast electrical consumption in the area without considering the combined impact of CDM and DG. As per the data provided by the study team, the gross load in the London Area is expected to grow at an average rate of approximately 0.9% annually from 2014 – 2023.

4.2 Net Load Forecast

The net load forecast builds from the gross load forecast and includes the planned CDM targets and DG contributions. For the London Area, the net load is expected to grow at an average rate of approximately 0.2% annually from 2014 – 2023.

5 NEEDS ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The assessment is based on summer peak loads.

2. Load data for transmission connected industrial customers in the region was assumed to be consistent with historical peak loads.

3. The LDC's load forecast is translated into load growth rates and is applied onto the 2013 summer peak load as a reference point.

4. Accounting for (2) and (3) mentioned above, the gross load forecast and a net load forecast were developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net load forecast which accounts for CDM and DG is analyzed to determine if needs can be deferred.

   A coincident version of the gross and net load forecast was used to assess the transformer capacity needs (section 6.1.1), 230 kV transmission line needs (section 6.1.2), 115 kV transmission line needs (6.1.3) and system reliability operation and restoration needs (6.2).

   A non-coincident version of the net load forecast was used to assess the station capacity as presented in section 6.1.4.

   A coincident peak load forecast and a non-coincident peak load forecast were produced for each gross load and net load forecasts.

5. Review impact of any on-going and/or planned development projects in the London Area during the study period.

6. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as autotransformers, cables, and stations.

7. 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 or the historical low voltage power factor, whichever is more conservative. For stations having low-voltage capacitor banks, a 95% lagging power factor was assumed or the historical low-voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR).

8. To identify emerging needs in the Region and determine whether or not further coordinated regional planning should be undertaken, the study was performed observing all elements in service and only one element out of service.

9. Transmission adequacy assessment is primarily based on, but is not limited to, the following criteria:

- With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.
- With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their summer or winter 10-Day LTR, as appropriate.
- All voltages must be within pre and post contingency ranges as per Ontario Resource and Transmission Assessment Criteria (ORTAC) (Section 4.2) criteria.
- With one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
- With two elements out of service, the system is capable of meeting the load restoration time limits as per ORTAC (Section 7.2) criteria.

6 RESULTS

This section summarizes the results of the Needs Assessment in the London Area.

6.1 Transmission Capacity Needs

6.1.1 230/115 kV Autotransformers

The 230/115 kV autotransformers (Buchanan TS and Karn TS) supplying the London Area are adequate over the study period for the loss of a single 230/115 kV autotransformer.

6.1.2 230 kV Transmission Lines

Overall, the 230 kV circuits supplying the London Area are adequate over the study period for the loss of a single 230 kV circuit in the Region.

Under high eastwardly flows and/or high generation conditions, W44LC, W45LS, N21W, N22W and S47C may be overloaded under pre-contingency conditions. This issue will be further assessed by IESO as part of bulk system planning.

6.1.3 115 kV Transmission Lines

The 115 kV circuit W8T from Buchanan TS to Edgeware JCT reaches its continuous rating under pre-contingency conditions in the near term based on the gross load forecast. Such thermal overload is deferred to the medium term based on the net load forecast. In addition, the 115kV system is also restricted for any new DG connections at Tillsonburg TS because of capacity limitation.

The remaining 115 kV circuits supplying the London Area are adequate over the study period for the loss of a single 115 kV circuit in the area.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV TSs in the London Area using the summer station peak load forecasts provided by the study team. The results are as follows:

Aylmer TS
Aylmer TS T2/T3 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 113% Summer 10-Day LTR in 2014).

Buchanan TS

Historical data shows that Buchanan DESN power factor is below ORTAC criteria under peak load conditions.

Clarke TS

Clarke TS T3/T4 exceeds its 10-Day LTR in 2014 based on the net load forecast (approximately 101% of Summer 10-Day LTR). Although based on the planned CDM targets and DG contributions, the station capacity for Clarke TS T3/T4 is adequate to meet the net forecasted demand over the remainder of the study period, loading at Clarke TS is above its LTR based on gross load.

Strathroy TS

Strathroy TS T1/T2 is forecasted to exceed its 10-Day LTR in 2014 based on the net load forecast (approximately 125% of Summer 10-Day LTR in 2014)

Talbot TS

Talbot TS T1/T2 and T3/T4 DESN is near its 10-Day LTR rating in the near term based on the net load forecast and is above its LTR based on gross load. The load forecast for Talbot TS increases significantly in year 2015 by 17MW based on the ongoing planning activities of the LDC to convert and transfer Nelson TS load to Talbot TS to accommodate the redevelopment plans of Nelson TS. The load transferred to Talbot TS in 2015 is temporary in nature, and will be transferred back to Nelson TS when the redevelopment is expected to be complete in 2019.

Tillsonburg TS

For the loss of T3, Tillsonburg TS T1 is forecasted to exceed its 10-Day LTR towards the end of the near term based on the net load forecast (approximately 102% of Summer 10-Day LTR in 2018) and is above its LTR based on gross load

Wonderland TS

For the loss of T6, Wonderland TS T5 is forecasted to exceed its 10-Day LTR 2014 based on the net load forecast (approximately 112% of Summer 10-Day LTR in 2014).

All the other TSs in the London Area are forecasted to remain within their normal supply capacity during the study period.

6.2 System Reliability, Operation and Restoration Review

Based on the net load forecast, the pre-contingency voltage at Tillsonburg TS 115kV is expected to be less than the minimum voltage level as established in Section 4.3 of the ORTAC.

Under peak load conditions with the Buchanan 115 kV capacitor in-service, the 115 kV voltage reaches its maximum limit. Accordingly, switching in any additional 230 kV capacitors at Buchannan becomes challenging. This is an operational issue and will be discussed between IESO and Hydro One.

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

Based on the gross coincident load forecast at Buchanan TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit line W42L and W43L. However, based on the net coincident load forecast, which accounts for CDM and DG, the load interrupted by configuration does not exceed 150 MW. Therefore, no action is required at this time and this will be reviewed in the next planning cycle.

Based on the gross and net coincident load forecast for Ingersoll TS and stations connected along the 115 kV circuits K7/K12/B8W, the load interrupted by configuration at peak will exceed 150 MW for the loss of double-circuit 230kV line M31W and M32W. Similarly, based on the gross and net coincident load forecast at Clarke TS and Talbot TS, the load interrupted by configuration will exceed 250 MW for the loss of double-circuit 230kV line W36 and W37. Furthermore, based on the gross and net coincident load forecast at Wonderland TS and Modeland TS, the load interrupted by configuration will exceed 150 MW for the loss of double-circuit 230kV line N21W and N22W.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Hydro One reviewed the sustainment and development initiatives that are currently planned for the replacement of any autotransformers, power transformers and high-voltage cables. These sustainment plans do not affect the results of this NA study. During the study period:

- The existing Aylmer TS will be replaced with a new DESN with two 25/33.3/41.7 MVA transformer and four feeder positions and is scheduled to be completed in 2019. The replacement plan will address the transformer capacity need identified in section 6.1.4.
- The existing Nelson TS DESN will be redeveloped to maintain supply to the area. Final arrangement will depend on the ongoing discussions between the Hydro One and the LDC. This NA study assumes the LDC’s plan to redevelop Nelson TS and convert the station LV from 13.8kV to 27.6kV.

- As part of the Burlington-Nanticoke Area Regional Infrastructure Planning, there is an ongoing plan to replace existing switches on B12/B13 with 115 kV breakers to address the voltage and capacity issue in the Brant area. This project will allow the existing normally-open points on B12/B13 to be operated normally-closed. The breakers cause no adverse impacts to the London Region. As the project is still in its planning phase, the ability to provide backup to the Woodstock area has not yet been confirmed.

7 RECOMMENDATIONS

Based on the findings and discussion in Section 6 of the Needs Assessment report, the study team recommends that the following needs should be further assessed as part of the Scoping Assessment to determine if CDM/DG can fully or partly address them or Wires Planning should be undertaken:

- Transformation capacity limitations at Strathroy TS, Tillsonburg TS, Wonderland TS, Clarke TS and Talbot TS
- Thermal and voltage limitations along the 115kV circuit W8T
- Load restoration concerns following the loss of two elements as described in section 6.2

The following need should be further assessed as part of local planning by Hydro One and relevant LDCs:

- Low power factor at Buchanan DESN

8 NEXT STEPS

IESO and Hydro One will initiate a SA and Local Planning process to address the relevant needs as per the recommendations in Section 7.

9 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013
ii) IESO 18-Month Outlook: March 2014 – August 2015
iii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

10 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
HVDS	High Voltage Distribution Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NA	Needs Assessment
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 Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

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LOCAL PLANNING REPORT

Strathroy TS Transformer Capacity
Region: London Area

Date: September 12, 2016
Revision: Final

Prepared by: Strathroy Sub-region Local Planning Study Team

This report is prepared on behalf of the Strathroy Sub-region Local Planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Entegrus Inc.
Hydro One Networks Inc. (Distribution)

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the London Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	London Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	June 17, 2016	**END DATE**	September 12, 2016

1. INTRODUCTION

In 2015, a Needs Assessment study was conducted to assess the transmission system supplying the London Region and a number of issues were identified. Subsequently, the IESO carried out its Scoping Assessment to determine the degree of regional coordination required to address each need. It was concluded that Strathroy TS transformer capacity need is local in nature and is best addressed by wires options through local planning led by Hydro One with participation of the impacted LDCs. The purpose of this Local Planning report is to develop wires-only options and recommend a preferred solution that will address the Strathroy TS transformation capacity need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's ("OEB") Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements and the "Planning Process Working Group (PPWG) Report to the Board".

2. LOCAL NEEDS ADDRESSED IN THIS REPORT

During Needs Assessment, it was forecasted that Strathroy TS transformer will exceed its capacity and this report is developed to address this transformer capacity need.

3. FINDINGS

Based on the updated load forecast information, while load at Strathroy TS is expected to experience a mild growth over the next ten years, there is sufficient transformer capacity at Strathroy TS over the study period.

4. CONCLUSION

The local planning study team agreed that no action is required at this time.

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1 Introduction

As part of the OEB-mandated regional planning process, a Needs Assessment study for London area was conducted in 2015 by Hydro One Transmission, Independent Electricity System Operator ("IESO"), Erie Thames Power, Entegrus, Hydro One Distribution, London Hydro, St. Thomas Energy, Tillsonburg Hydro and Woodstock Hydro. The study assessed the electricity infrastructure supplying the London Region for the ten – year period starting from 2014 and it identified a number of constraints in the area. The IESO subsequently carried out its Scoping Assessment and concluded that, among other things, need in the Strathroy sub-region should be addressed through Local Planning between Hydro One Transmission and impacted local distribution companies ("LDCs").

This Local Planning report was prepared for the purposes of addressing the Strathroy TS transformation capacity need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

1.1 Geographical Area and Existing Supply Network

Strathroy Transformer Station ("TS") is a transmission substation that is located in Middlesex County in Southwestern Ontario and supplies the surrounding mainly-rural area, including the Middlesex county and townships of Adelaide-Metcalfe, Warwick, Strathroy-Caradoc. Presently, Strathroy TS is supplied radially from Buchanan TS, 45 km to the east, via 115 kV circuit W2S. Alternately, it can be supplied from the west from Scott TS via 115 kV circuit S2N. Strathroy TS houses two 25/33/42 MVA 110/28 kV step-down transformers and currently supplies Entegrus and Hydro One Distribution at 27.6 kV level.

Following the replacement of transformer T2 at Strathroy TS in August 2012, there is plan in place to replace T1 like-for-like by 2017.

The physical location of Strathroy TS and the existing substation assets are shown in Figure 1 and Figure 2 respectively.

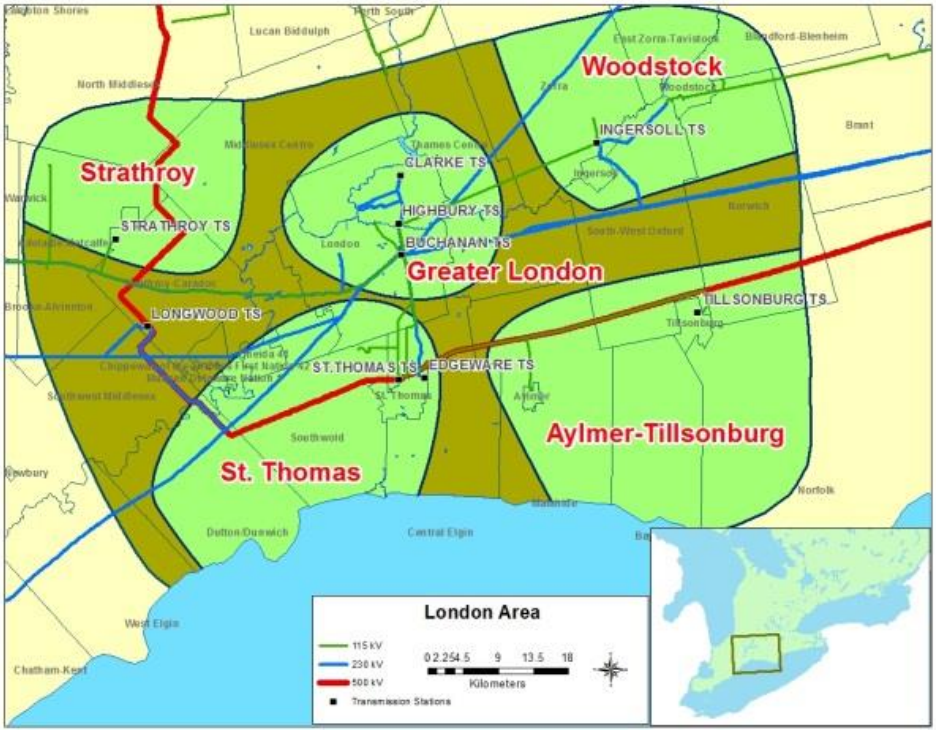

Figure 1 – Map of Strathroy Sub-region and London Region

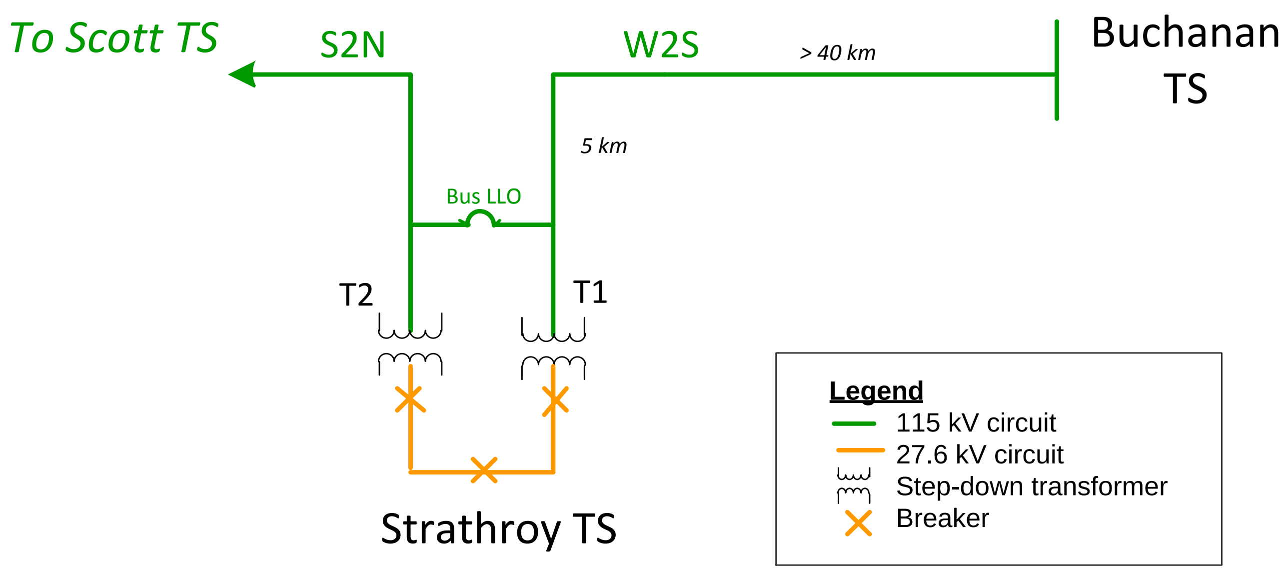

Figure 2 – Simplified schematic of Strathroy TS

2 Load Forecast

Ten – year electricity load forecast was prepared with inputs from downstream LDCs and the IESO. Entegrus and Hydro One Distribution provided gross load forecasts for 2016 – 2025. The station gross load forecast was then extrapolated by applying the corresponding annual growth rates to 2015 historical demand. The net load forecast takes account of conservation demand management ("CDM") programs and distributed generation ("DG") in the distribution network that are either presently in place or foreseen by the IESO, each of which may have the effect of reducing the forecast demand to be supplied. The forecasted CDM achievement in Strathroy TS is represented by percentages reduction applied to gross peak demand and DG information represents the annual incremental, effective capacity of all generation contracts with the IESO. The 2015 observed station peak for Strathroy TS is 38.9 MW and for planning purpose, the reference point of the forecast was adjusted upward by 6% to account for extreme weather correction. The resultant net load forecast is tabulated in Table 1.

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Station Gross Load		41.8	42.2	42.7	43.1	43.6	44.1	44.6	45.1	45.6	46.1
Incremental DG		0.15	0	0	0	0	0	0	0	0	0
CDM		1%	2%	3%	4%	5%	5%	6%	6%	7%	7%
Station Net Load	41.3	41.1	41.5	41.4	41.5	41.6	41.8	42.0	42.2	42.5	42.8

Table 1 – Ten-year load forecast for Strathroy TS (MW)

3 Assessment and Findings

The Ontario Resource and Transmission Assessment Criteria ("ORTAC") outlines the supply reliability planning requirements to ensure loading on transmission network does not exceed equipment ratings under both normal and contingency operating conditions. For transformer, in the event where one of the two transformers in a substation suffers an outage, namely a (N – 1) event, loading of the remaining transformer should not exceed its 10 – day limited time rating ("LTR").

At the time of this assessment, the 10 – Day Summer LTR rating for Strathroy TS is 53 MVA (or 50.4 MW at 0.95 power factor)[1]. During Needs Assessment, the combined station load was forecasted to exceed 50 MW in the near term, which means the remaining transformer could be overloaded for the loss its companion transformer. However, in examining the revised and updated load forecast, the 2015 historical actual is tracking 23% lower than the forecasted level in the Needs Assessment and in fact, the revised ten – year net forecast is 17% less than what was previously assumed in Needs Assessment. The downward adjustment

[1] 10 – Day LTR of 53 MVA is rated at 30 °C ambient temperature.

in station load forecast has meant that for the loss of one of the two transformers, the remaining transformer is capable of supplying all of Strathroy TS load while remaining under its 10 – Day LTR rating for the entire study period.

4 Conclusion

Based on the information provided in this report, there is sufficient transformer capacity at Strathroy TS to meet expected load growth over the ten – year study period between 2016 and 2025. Therefore, Entegrus, Hydro One Distribution and Hydro One Transmission agreed that no action is required at this time. Further, the study team will continue to monitor and track the development in the Strathroy sub-region and reconvene should unforeseen needs emerge prior to the next planning cycle starting in 2018.

5 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] London Region Needs Assessment Report

[4] London Region Scoping Assessment Report

Appendix A: Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
DSC	Distribution System Code
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
TSC	Transmission System Code

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LOCAL PLANNING REPORT

Woodstock Sub-region Restoration
Region: London Area

Date: May 19, 2017
Revision: Final

Prepared by: Woodstock Sub-region Local Planning Study Team

This report is prepared on behalf of the Woodstock Sub-region Local Planning study team with the participation of representatives from the following organizations:

Organizations
Hydro One Networks Inc. (Lead Transmitter)
Erie Thames Powerlines Corporation
Hydro One Networks Inc. (Distribution)

Disclaimer

This Local Planning Report was prepared for the purpose of developing wires-only options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment (NA) report for the London Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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LOCAL PLANNING EXECUTIVE SUMMARY

REGION	London Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	September 16, 2016	**END DATE**	May 19, 2017

1. INTRODUCTION

In 2015, a Needs Assessment study was conducted to assess the transmission system supplying the London Region and a number of issues were identified. Subsequently, the IESO carried out its Scoping Assessment to determine the degree of regional coordination required to address each need. It was concluded that Woodstock sub-region restoration need is local in nature and is best addressed by wires options through local planning led by Hydro One with participation of the impacted LDCs. The purpose of this Local Planning report is to develop wires-only options and recommend a preferred solution that will address the Woodstock sub-region restoration need referenced in both Needs Assessment and the Scoping Assessment reports for London Area.

The development of the LP report is in accordance with the regional planning process as set out in the Ontario Energy Board's ("OEB") Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements and the "Planning Process Working Group (PPWG) Report to the Board".

2. LOCAL NEED ADDRESSED IN THIS REPORT

During Needs Assessment, it was identified that more than 180 MW of load will be interrupted by configuration following the simultaneous loss of the 230 kV supply circuits M31W/M32W and this report is developed to address the restoration need.

3. FINDINGS

Based on the updated load forecast and transfer capability information, there is sufficient transfer capability in the existing system to restore interrupted loads from neighbouring regions within prescribed time frames and therefore, satisfying the restoration criteria.

4. CONCLUSION

The local planning study team agreed that no action is required at this time.

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1 Introduction

As part of the OEB-mandated regional planning process, a Needs Assessment study for London area was conducted in 2015 by Hydro One Transmission, Independent Electricity System Operator ("IESO"), Erie Thames Powerlines, Entegrus, Hydro One Distribution, London Hydro, St. Thomas Energy, Tillsonburg Hydro and Woodstock Hydro. The study assessed the electricity infrastructure supplying the London Region for the ten – year period starting from 2014 and it identified a number of constraints in the area. The IESO subsequently carried out its Scoping Assessment and concluded that, among other things, need in the Woodstock sub-region should be addressed through Local Planning between Hydro One Transmission and impacted local distribution companies ("LDCs").

This Local Planning report was prepared for the purposes of addressing the Woodstock sub-region M31W/M32W restoration need referenced in both Needs Assessment and the Scoping Assessment reports for London Area. Following the acquisition of Woodstock Hydro, the Woodstock sub-region Local Planning study team is consist of Erie Thames Powerlines, Hydro One Distribution and Hydro One Transmission.

1.1 Geographical Area and Existing Supply Network

The Woodstock sub-region is located in southwestern Ontario and includes town of Ingersoll, City of Woodstock and rest of northern part of Oxford County.

Woodstock sub-region's electricity demand is a mix of residential, commercial and industrial loads. There is no major generation facility in the Woodstock sub-region and power is delivered by the 230 kV and 115 kV transmission lines in the vicinity. The 230 kV double circuit line, M31W and M32W connecting Buchanan TS and Middleport TS, is tapped off at Salford Junction and supplies Karn TS and step-down transformer station Ingersoll TS. Karn TS currently houses two autotransformers which were placed in-service in 2011 as part of the "Woodstock Area Transmission Reinforcement" project and they provide necessary transformation from 230 kV level to 115 kV level. The 115 kV double circuit lines K7/K12 supplied out of Karn TS are approximately 22 km in length and the three transformer stations connected – namely Woodstock TS, Commerce Way TS, and Toyota Woodstock TS – step 115 kV transmission voltage level down to lower distribution voltages for serving customers in the area. Electricity distribution services to customers in the Woodstock sub-region are provided by Erie Thames Powerlines and Hydro One Distribution.

A map of the Woodstock sub-region and schematic of the existing transmission system of the area are shown in Figure 1 and Figure 2 respectively.

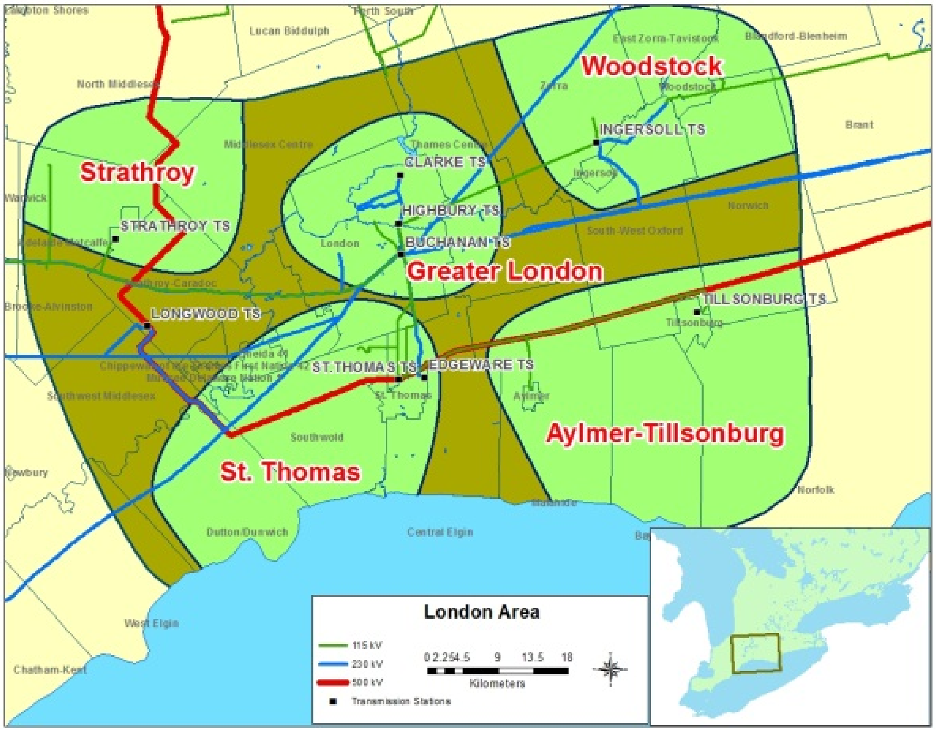


Figure 1 – Map of Woodstock Sub-region and London Region

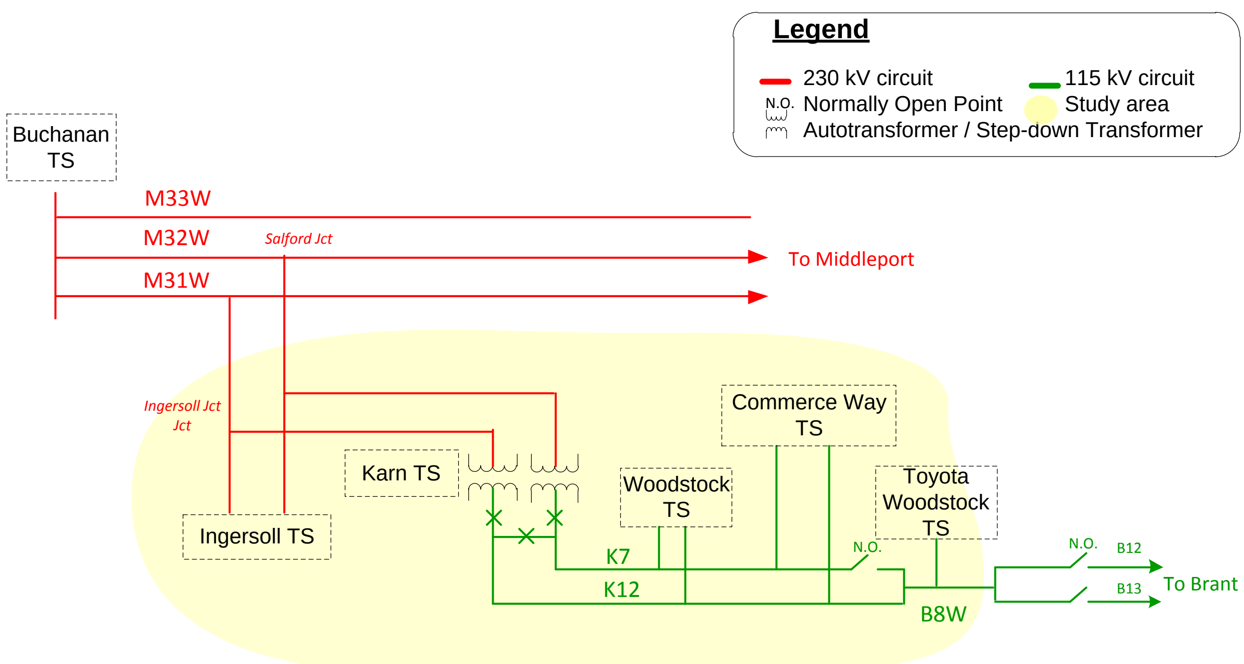


Figure 2 – Simplified schematic of Woodstock sub-region transmission system

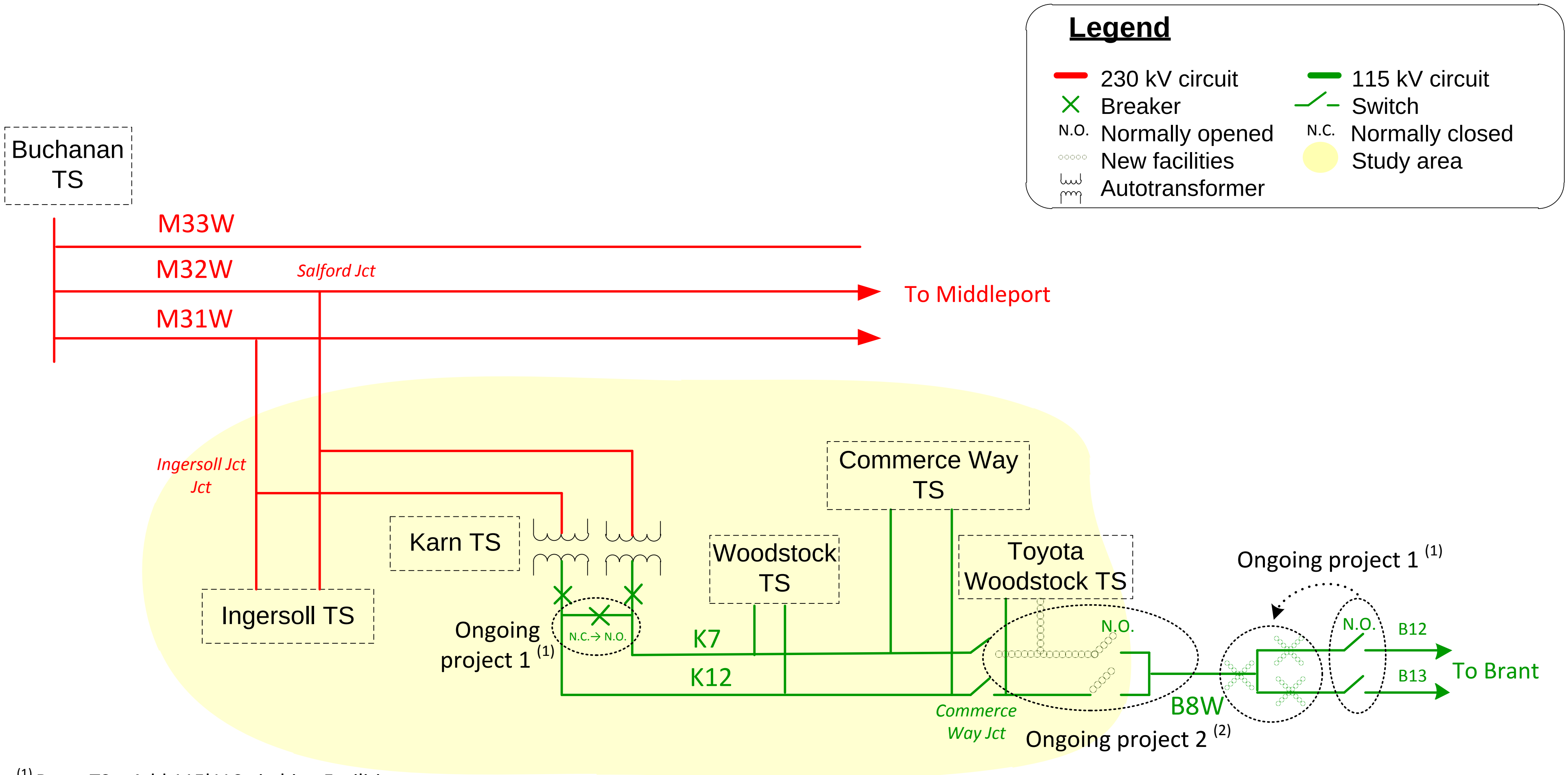
1.2 Planned and Committed Facilities

There are several projects currently under development or being planned to address immediate and near term customer needs and reliability issues within the Woodstock sub-region and neighbouring region.

As shown in Figure 2, Woodstock subsystem and Brant subsystem are electrically isolated at the normally-opened points on B12/B13 circuits. In 2015, the Brant Integrated Regional Resource Plan (“IRRP”) study team comprising of Brant County Power Inc., Brantford Power Inc. Hydro One Distribution, Hydro One Transmission and the IESO recommended new switching facilities to be built at Brant TS to address the near term capacity needs in the Brant-Powerline 115 kV sub-system. By replacing the existing normally-opened points on B12/B13 and B8W with three 115 kV breakers and operating the Karn TS 115 kV tie breaker normally open, this project will provide additional supply capacity to the Brant-Powerline 115 kV sub-system. Further, measures will be in place for B8W in-line breaker to be automatically opened for loss of both Karn TS autotransformers. As a result of this project, the Woodstock sub-region will be connected to its neighbouring Brant sub-region electrically in normal operating conditions. The proposed in-service date for this project is Q1 2019. Hydro One brought forward this proposal in its transmission rates application (EB-2016-0160).

Development for a new overhead extension of 115 kV circuit K7/B8W 3 km in length from Commerce Way Junction to Toyota Woodstock TS and a new step-down transformer at Toyota Woodstock TS is currently underway at customer’s request to improve supply reliability. The project will be subject to OEB’s Leave-to-Construct Section 92 Approval process and the target in-service date is Q1 2019.

These reinforcements are summarized pictorially in Figure 3.



(1) Brant TS – Add 115kV Switching Facilities

(2) Toyota Woodstock TS – Conversion to DESN Configuration

Figure 3 – Planned and committed transmission projects in the Woodstock sub-region

2 Load Forecast

Ten – year electricity load forecast was prepared with inputs from downstream LDCs and the IESO. Erie Thames Powerlines and Hydro One Distribution provided gross load forecasts for 2016 – 2025 inclusive. The station gross load forecast was then extrapolated by applying the corresponding annual growth rates to 2015 historical demand. The Woodstock sub-regional actual coincident peak load in 2015 was approximately 182 MW and for planning purpose, the reference points of step-down transformer stations were adjusted upward by 2 – 4% to account for extreme weather correction[1]. The net load forecast takes account of conservation and demand management ("CDM") programs and distributed generation ("DG") in the distribution network that are either presently in place or foreseen by the IESO, each of which may have the effect of reducing the forecast demand to be supplied. The DG information included represents the annual incremental, effective capacity of all generation contracts with the IESO and in combination with forecasted CDM, they reflect reduction applied to gross peak demand.

Assuming that large industrial customer load will maintain at its current 20 MW level, the total load in the Woodstock sub-region will remain above 180 MW throughout the study period.

The resultant net load forecast on a station basis is tabulated in Table 1.

(MW)		2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Commerce Way TS	Station Gross Load		34.9	35.0	35.1	35.3	35.4	35.5	35.6	35.8	35.9	36.0
	Incremental DG		0.03	0	0	0	0	0	0	0	0	0
	CDM		0.4	0.6	1.0	1.4	1.7	1.9	2.1	2.2	2.4	2.6
	Station Net Load	33.4	34.5	34.4	34.1	33.9	33.7	33.6	33.5	33.5	33.5	33.4
Ingersoll TS	Station Gross Load		76.4	76.5	76.6	76.6	76.7	76.8	76.9	77.0	77.1	77.2
	Incremental DG		0.00	0.20	0.49	0	0	0	0	0	0	0
	CDM		0.8	1.4	2.2	3.0	3.6	4.1	4.5	4.8	5.2	5.6
	Station Net Load	75.1	75.6	74.9	73.9	73.7	73.1	72.8	72.4	72.2	71.9	71.6
Woodstock TS	Station Gross Load		58.3	58.5	58.7	58.9	59.1	59.3	59.5	59.7	60.0	60.2
	Incremental DG		0.02	0.24	0	0	0	0	0	0	0	0
	CDM		0.6	1.0	1.7	2.3	2.8	3.1	3.5	3.7	4.1	4.3
	Station Net Load	56.5	57.6	57.2	57.0	56.6	56.3	56.2	56.0	56.0	55.9	55.8
Toyota Woodstock TS	Station Load*		20	20	20	20	20	20	20	20	20	20
Woodstock Sub-region Total Net Load			188	186	185	184	183	182	182	182	181	181

* Assumed load, based on Hydro One Transmission's information

Table 1 – Ten-year load forecast for Woodstock sub-region (MW)

3 Assessment and Findings

The Ontario Resource and Transmission Assessment Criteria ("ORTAC") outlines the supply reliability planning requirements to ensure loading on transmission network does not exceed equipment ratings under both normal and contingency operating conditions. Among other things,

[1] Weather correction factors for Commerce Way TS, Ingersoll TS and Woodstock TS are 4%, 2% and 3% respectively

the supply restoration criteria in ORTAC requires that in the planning of electrical services to an area, the delivery system needs to have sufficient ability to restore interrupted load in a reasonable time following the critical double-element of [N – 2] contingency. Specifically, for interrupted load of over 250 MW, the portion above 250 MW must be restored within 30 minutes. For interrupted load level between 150 and 250 MW, the portion above 150 MW must be restored within 4 hours with the reminder restored in 8 hours. Additionally, the maximum amount of load that can be interrupted under the security criterion for a [N – 2] contingency is 600 MW. The application of the security criterion identifies when an area would require an alternative source of supply or a greater diversity of supply to maintain an adequate level of security.

For Woodstock sub-region, the critical line section for [N – 2] contingency is M31W/M32W tap between Salford Junction and Ingersoll Junction, which is approximately 11 km in length. Should this contingency occur, all of the sub-region load, which amounts to 188 MW in 2016 (Table 1), would be interrupted by configuration. In accordance with ORTAC, the system is required to restore 38 MW within 4 hours and the remaining 150 MW within 8 hours.

Under such emergency conditions, depending on system performance and availability of switching facilities, all or a portion of a load station could be restored by transferring load to neighbouring unaffected supply. Hydro One Distribution estimated 10 MW of load at Ingersoll TS can be transferred to Highbury TS. Another 8 MW could be transferred from Commerce Way TS to Tillsonburg TS on the feeder level. On the transmission side, the supply from Brant will be able to restore about 20 MW of load in the Woodstock sub-region before minimum allowable post-contingency voltage limit of 108 kV is reached[2]. These measures can be deployed remotely to manage and mitigate the impact of the [N – 2] contingency within the 4 hours timeframe. To restore the remaining 150 MW of interrupted load within 8 hours, field crew from the nearest staffed centre in London area will be dispatched and install temporary fixes on the transmission system such as building emergency by-pass.

4 Conclusion

Based on the information provided in this report, there is sufficient transfer capability on existing system to meet restoration criteria over the ten – year study period between 2016 and 2025. Therefore, Erie Thames Powerlines, Hydro One Distribution and Hydro One Transmission agreed that no further action is required at this time. The study team will continue to monitor and track the development in the Woodstock sub-region and reconvene should unforeseen needs emerge prior to the next regional planning cycle starting in 2018.

[2] Based on the load forecast for stations connected to B12/B13 as documented in Brant IRRP and Burlington to Nanticoke Local Planning report: combined loading of 158 MW was assumed for Powerline MTS and Brant TS; 54 MW for Dundas TS #2.

5 References

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC)

[3] London Region Needs Assessment Report

[4] London Region Scoping Assessment Report

Appendix A: Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
DSC	Distribution System Code
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Planning
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
TSC	Transmission System Code

Appendix D

1) Needs Assessment Report – Greater Bruce / Huron
2) Local Planning Report – Bruce HWB TS Power Factor Assessment
3) Local Planning Report – L7S Thermal Overload
4) Local Planning Report – Wingham TS Power Factor Assessment

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NEEDS ASSESSMENT REPORT

Region: Greater Bruce – Huron

Revision: Final

Date: May 6, 2016

Prepared by: Greater Bruce-Huron Study Team

Distribution

Transmission

Greater Bruce-Huron Region Study Team
Organization
Entegrus
Erie Thames Power
Festival Hydro Inc.
Goderich Hydro - West Coast Huron Energy Inc.
Hydro One Networks Inc. (Distribution)
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator
Wellington North Power Inc.
Westario Power Inc.

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Greater Bruce-Huron Region and to assess whether those needs require further coordinated regional planning. The potential needs that have been identified through this Needs Assessment Report may be studied further through subsequent regional planning processes and may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Needs Assessment Report are based on the information and assumptions provided by study team participants.

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NEEDS ASSESSMENT EXECUTIVE SUMMARY

REGION	Greater Bruce-Huron Region (the Region)		
LEAD	Hydro One Networks Inc. (Hydro One)		
START DATE	February 29, 2016	**END DATE**	April 28, 2016

1. INTRODUCTION

The purpose of this Needs Assessment report is to undertake an assessment of the Greater Bruce-Huron Region and determine if there are regional needs that require coordinated regional planning. Where regional coordination is not required, and a "localized" wires solution is necessary, such needs will be addressed between relevant Local Distribution Companies (LDCs) and Hydro One and other parties as required.

For needs that require further regional planning and coordination, the Independent Electricity System Operator (IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or whether both are required.

2. REGIONAL ISSUE/ TRIGGER

The Needs Assessment for the Greater Bruce-Huron Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups - Group 1 Regions are being reviewed first. The Greater Bruce-Huron Region belongs to Group 3. The Needs Assessment for this Region was triggered on February 29, 2016 and was completed on April 28, 2016.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment was limited to the next 10 years as per the recommendations of the Planning Process Working Group Report to the OEB.

The scope of the Needs Assessment includes a review of transmission system capability which covers transformer station capacity, transmission circuit thermal capacity, and voltage performance. System reliability, operational issues and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

Needs emerging over the next 10 years and requiring coordinated regional planning may be further assessed as part of the IESO-led Scoping Assessment and/or IRRP, or in the next planning cycle. If required, an IRRP will develop a 20-year strategic direction for the Region.

4. INPUTS/DATA

Study team participants, including representatives from LDCs, the IESO, and Hydro One transmission provided information for the Greater Bruce-Huron Region. The information included: planning activities already underway, historical load and power factor, load forecast, conservation and demand management (CDM) and distributed generation (DG) information, system reliability performance, operational issues and major equipment approaching end-of-life.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective was to identify the electrical infrastructure needs in the Region over the study period (2016 to 2025). The assessment reviewed available information and load forecasts and included single contingency analysis to identify needs.

6. RESULTS

Transmission System Capacity Needs

A. 230/115 kV Autotransformer Capacity

- Based on the gross regional-coincident load forecast, the 230/115 kV autotransformer capacity (Seaforth TS, Hanover TS) supplying the Region is adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

B. 230 kV Transmission Lines

- Based on the gross regional-coincident load forecast, the 230 kV circuits supplying the Region are adequate over the study period for the loss of a single 230 kV circuit in the Region.

C. 115 kV Transmission Lines

- Based on the gross regional-coincident load forecast, thermal limits for 115 kV circuit L7S between Seaforth Junction and Kirkton Junction will be exceeded in the near term (summer 2019) for the loss of 115 kV circuit D8S.
- Based on the net regional-coincident load forecast, the need date is expected to be deferred to the end of the study period.
- Due to the limited recorded effectiveness of CDM uptake in this Region, further study is required to identify an action plan.
    - The Need will be managed via Local Planning with the Region's study team.

D. 230 kV and 115 kV Connection Facilities

- Based on the gross non-coincident load forecast, the capacity of the 230 kV and 115 kV connection facilities in the Region are adequate over the study period.

System Reliability, Operation and Restoration Needs

A. Load Security

- Based on the gross regional-coincident load forecast and the existing transmission configuration, load security criteria can be met over the study period.

B. Load Restoration

- Based on the gross regional-coincident load forecasts with the use of existing transmission infrastructure, restoration criteria can be met over the study period.

C. Power Factor at Connection Facilities

- Historically, power factor at Wingham TS and Bruce HWP B TS do not meet Market Rule requirements.
    - The Need at Wingham TS will be managed via Local Planning between the transmitter and the affected LDCs.
    - The Need at Bruce HWP B TS will be managed via Local Planning between the transmitter

and the affected customer.

D. Voltage Performance

- Under gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result in poor end-of-feeder voltages (winter 2020/2021).
- Based on the net regional-coincident peak load forecast at Wingham TS, the need date may be deferred by 2 years.
- Due to the synergy between voltage performance and power factor, this voltage deficiency Need will be further studied in coordination with Wingham TS's power factor.
    - The Need will be managed via Local Planning between the transmitters and the affected LDCs

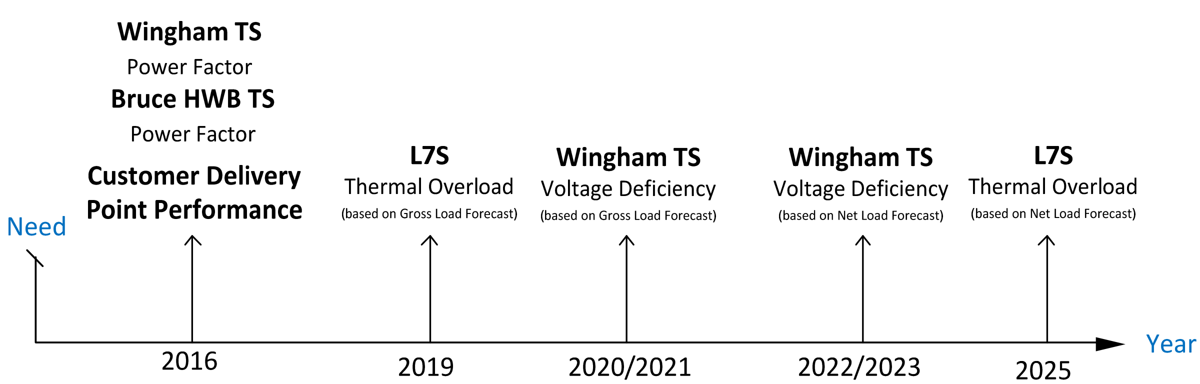
E. Customer Delivery Point Performance

- Based on a review of delivery point performance, several customer delivery points in the Region are below their historical measures.
    - Mitigation measures that align with Hydro One's OEB-approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

F. Bulk Power System Performance in the Region

- Based on a limited analysis of the bulk power system in the Region, 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is over its thermal limit near the end of the study period. This result is consistent with the KWCG Regional Infrastructure Plan (RIP) findings.
    - As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

Needs Timeline Summary



Aging Infrastructure / Replacement Plan

During the study period, plans to replace aged equipment at ten stations and several transmission circuits will take place. The replacement of aged equipment may improve customer delivery point performance. Investigation into customer delivery point performance will take into consideration this replacement work.

Further details of these investments can be found in Section 6.3 of this report.

7. RECOMMENDATIONS

Based on the findings of this Needs Assessment, the study team recommendations:

1. Poor power factor and voltage deficiency at Wingham TS to be managed by Local Planning between Hydro One transmission and Hydro One distribution and may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS

2. Poor power factor at Bruce HWP B TS to be managed by Local Planning between Hydro One transmission and the transmission connected customer.

3. Mitigation of poor delivery point performance to several 115 kV connected customers to be managed according to Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers.

4. Thermal overload on circuit L7S to be managed by Local Planning between Hydro One transmission and the Region's study team.

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1 INTRODUCTION

This Needs Assessment report provides a description of the analysis to identify needs that may be emerging in the Greater Bruce-Huron Region (the Region) over the next ten years. The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's (OEB) Transmission System Code (TSC) and Distribution System Code (DSC) requirements and the Planning Process Working Group (PPWG) Report to the OEB.

The purpose of this Needs Assessment report is to: consider the information from planning activities already underway; undertake an assessment of the Greater Bruce-Huron Region to identify near term and/or emerging needs in the area; and determine if these needs require a "localized" wires only solution(s) in the near-term and/or a coordinated regional planning assessment. Where a local wires only solution is necessary to address the needs, Hydro One, as transmitter, with LDCs or other connecting customer(s) will further undertake planning assessments to develop options and recommend solution(s). For needs that require further regional planning and coordination, the Independent Electricity System Operator (the IESO) will initiate the Scoping Assessment process to determine whether an IESO-led Integrated Regional Resource Planning (IRRP) process, or the transmitter-led Regional Infrastructure Plan (RIP) process (wires solution), or both are required.

This report was prepared by Hydro One (Lead Transmitter) with input from the Greater Bruce-Huron Region Needs Assessment study team listed in Table 1. The report captures the results of the assessment based on information provided by LDCs and the IESO.

Table 1: Study Team Participants for Greater Bruce-Huron Region

No.	Company
1	Hydro One Networks Inc. (Lead Transmitter)
2	Entegrus
3	Erie Thames Power
4	Festival Hydro Inc.
5	Goderich Hydro - West Coast Huron Energy Inc.
6	Hydro One Networks Inc. (Distribution)
7	Independent Electricity System Operator
8	Wellington North Power Inc.
9	Westario Power Inc.

2 TRIGGER OF NEEDS SCREEN

The Needs Assessment for the Greater Bruce-Huron Region was triggered in response to the Ontario Energy Board's (OEB) Regional Infrastructure Planning process approved in August 2013. To prioritize and manage the regional planning process, Ontario's 21 regions were assigned to one of three groups, where Group 1 Regions are being reviewed first. The Region falls into Group 3. The Needs Assessment for this Region was triggered on February 29, 2016 and was completed on April 28, 2016.

3 SCOPE OF NEEDS ASSESSMENT

This Needs Assessment covers the Greater Bruce-Huron Region over an assessment period of 2016 to 2025. The scope of the Needs Assessment includes a review of transmission system connection facility capability which covers transformer station capacity, transmission circuit thermal capacity, and voltage performance. System reliability, operational issues such as load restoration, and asset replacement plans were also briefly reviewed as part of this Needs Assessment.

3.1 Greater Bruce-Huron Region Description and Connection Configuration

The Greater Bruce-Huron Region includes the counties of Bruce, Huron and Perth, as well as portions of Grey, Wellington, Waterloo, Oxford and Middlesex counties. The boundary of the Greater Bruce-Huron Region is shown in Figure 1.

Figure 1: Greater Bruce-Huron Region Map

Electricity supply for the Region is provided through a network of 230 kV and 115 kV transmission lines supplied mainly by generation from the Bruce Nuclear Generating Station and local renewable generation facilities in the Region. The bulk of the electrical supply is transmitted through 230 kV circuits (B4V, B5V, B22D, B23D, B27S and B28S) radiating out from Bruce A TS. These circuits connect the Region to the adjacent South Georgian Bay/Muskoka Region and the adjacent Kitchener-Waterloo-Cambridge-Guelph (KWCG) Region.

Listed in Table 2 and shown in Figure 2, are the transmission and transmission connected assets in the Greater Bruce-Huron Region.

Table 2: Hydro One and Customer Assets Bounded by the Greater Bruce-Huron Region

115 kV Circuits	230 kV Circuits	Hydro One Transformer Stations	Customer Transformer Stations
61M18, D8S, D10H, L7S, S1H	B4V, B5V, B22D, B23D, B20P, B24P, B27S, B28S, B81HW, B82HW	Bruce HWP B TS, Centralia TS, Douglas Point TS, Goderich TS, Hanover TS, Owen Sound TS, Palmerston TS, Seaforth TS, St. Marys TS, Stratford TS, Wingham TS	Constance DS, Festival MTS, Grand Bend East DS, Customer CTS #1, Customer CTS #2, Customer CTS #3, Customer CTS #4

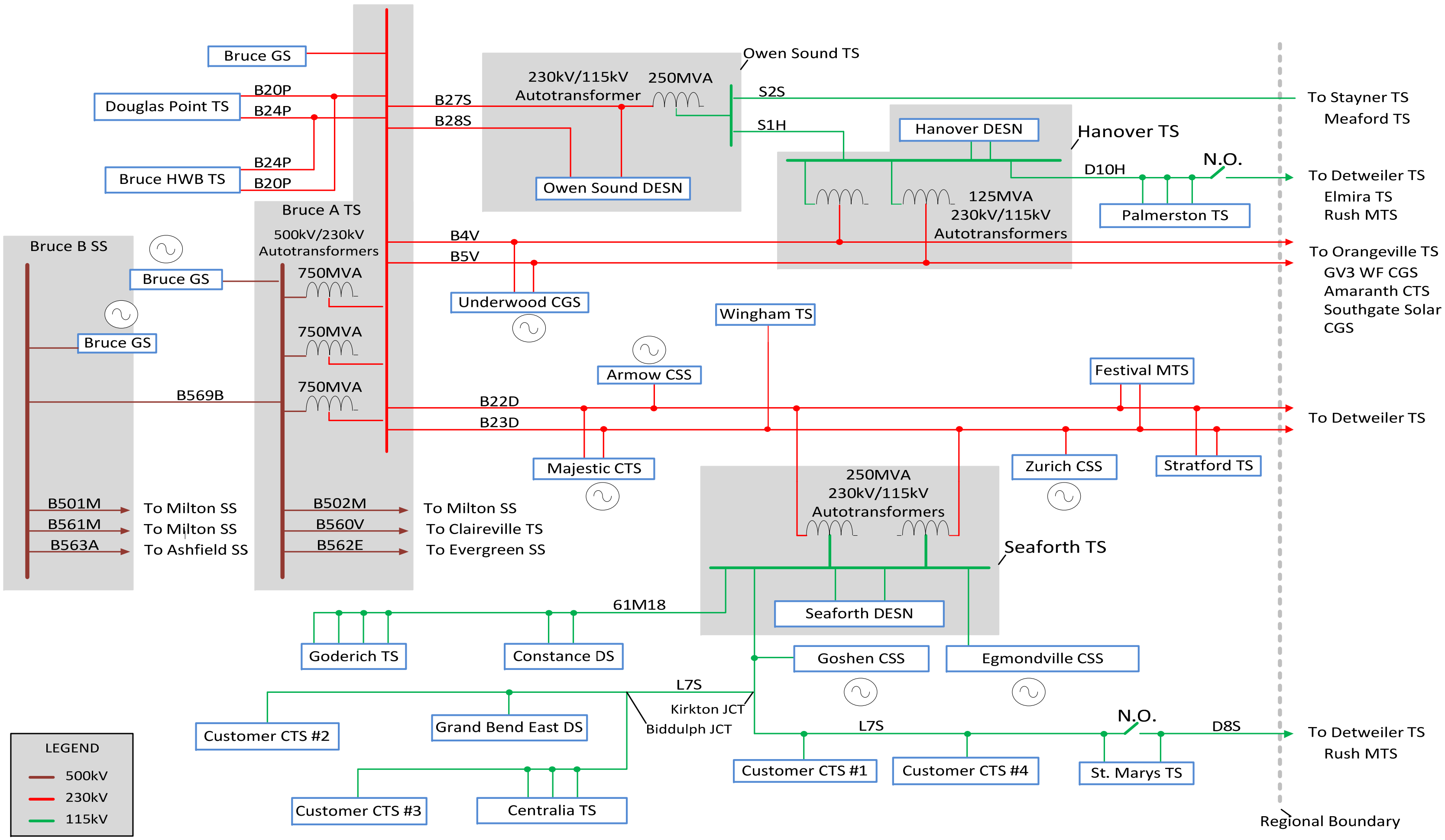

Figure 2: Single Line Diagram – Greater Bruce-Huron Region

4 INPUTS AND DATA

In order to conduct this Needs Assessment, study team participants provided the following information to Hydro One:

- IESO provided:
    1. Historical regional coincident peak load and station non-coincident peak load
    2. List of existing reliability and operational issues
    3. Conservation and Demand Management (CDM) and Distributed Generation (DG) data
    4. Historical power factor data, MW and MVar for each station in the Region
- LDCs provided historical summer and winter net load (2013-2015) as well as summer and winter gross load forecast (2016-2025)
- Hydro One (Transmission) provided transformer, station and circuit ratings
- Hydro One (Transmission) provided existing reliability and operation issues
- Any relevant planning information, including planned transmission and distribution investments are provided by Hydro One (Transmission) and LDCs

4.1 Load Forecast

As per the data provided by the study team, the winter *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.1% annually from 2016-2025 and the summer *gross* coincident load in the Region is expected to grow at an average rate of approximately 1.0% from 2016-2025.

As per the data provided by the study team, the winter *net* coincident load in the Region is expected to grow at an average rate of approximately 0.5% annually from 2016-2025 and the summer *net* coincident load in the Region is expected to grow at an average rate of approximately 0.3% from 2016-2025.

Based on historical load and on the load forecast, the Regions' winter coincident peak load is larger than its summer coincident peak load. As well, the majority of stations within the Region are winter peaking. The load forecasts utilized for this Needs Assessment are found in Appendix A: Load Forecasts.

5 NEEDS ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

1. The Region contains some stations that are summer peaking and others that are winter peaking. Equipment ratings are normally lower in the summer than winter due to ambient temperature. Based on these factors this assessment is conducted for both summer and winter peak load.
2. Forecast loads are provided by the Region's LDCs using historical 2015 summer and historical 2014/2015 winter peak loads as reference points.
3. Forecast loads are provided by industrial customers in the Region. Where data was not provided, the load is assumed to be consistent with historical loads.
4. The historical peak loads are adjusted for extreme weather conditions according to Hydro One methodology.
5. The LDC's load forecast is translated into load growth rates and is applied onto the historical, extreme weather adjusted, reference points.
6. Accounting for (2), (3), (4), (5) above, a gross load forecast and a net load forecast are developed. The gross load forecast is used to develop a worst case scenario to identify needs. Where there are issues, the net forecast, which accounts for CDM and DG, is analyzed to determine if the needs can be deferred.
    a. A gross and net non-coincident peak load forecast was used to perform the analysis for sections 6.1.4 and 6.2.3
    b. A gross and net regional-coincident peak load forecast was used to perform the analysis for sections 6.1.1 to 6.1.3 and 6.2.1 and 6.2.2 and 6.2.4
7. Review impact of any on-going and planned development projects in the Region during the study period.
8. Review and assess impact of any critical/major elements planned/identified to be replaced at the end of their useful life such as transformers, cables, and stations.
9. Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity by assuming a 90% lagging power factor for stations without low-voltage capacitor banks or the historical low voltage power factor, whichever is more conservative. Normal planning supply capacity for transformer stations in this Region is determined by the summer and winter 10-Day Limited Time Rating (LTR), as appropriate.
10. Transmission adequacy assessment is primarily based on the following criteria:
    - Regional load is set to the forecasted regional-coincident peak load
    - With all elements in service, the system is to be capable of supplying forecast demand with equipment loading within continuous ratings and voltages within normal range.

- With one element out of service, the system is to be capable of supplying forecast demand with circuit loading within their long-term emergency (LTE) ratings and transformers within their 10-Day LTR.
- All voltages must be within pre and post contingency ranges as per the Ontario Resource and Transmission Assessment Criteria (ORTAC).
- The system to meet load security criteria as per the ORTAC, specifically, with one element out of service, no more than 150 MW of load is lost by configuration. With two elements out of service, no more than 600 MW of load is lost by configuration.
- The system is capable of meeting the load restoration timeframes as per the ORTAC.

6 RESULTS

This section summarizes the results of the Needs Assessment in the Greater Bruce-Huron Region. The results are based on all 8 Bruce nuclear generating units in-service and no local/renewable generating units in-service in order to verify whether the transmission system has adequate capacity to supply the forecasted regional load.

6.1 Transmission System Capacity Needs

6.1.1 230 kV and 115 kV Autotransformers

The 230/115 kV autotransformers (Seaforth TS, Hanover TS, Detweiler TS, Owen Sound TS) supplying the Region are adequate over the study period for the loss of a single 230/115 kV autotransformer in the Region.

6.1.2 230 kV Transmission Lines

The 230 kV lines supplying the Region are double circuit. The 230 kV circuits are adequate over the study period for the loss of a single 230 kV circuit in the Region.

6.1.3 115 kV Transmission Lines

The 115 kV lines supplying the Region are radial single circuit lines. These 115 kV circuits have adequate capacity over the study period.

115 kV circuit L7S that runs between Seaforth TS and St. Mary’s TS is connected to 115 kV circuit D8S that runs between St. Marys TS and Detweiler TS, through the St. Marys TS low voltage bus-tie breaker. For the loss of D8S, L7S will exceed its short-term emergency (STE) and LTE ratings in the near term (summer 2019), under summer *gross*

peak load conditions. Under summer *net* peak load conditions, the flow on L7S decreases to ~97% of its emergency ratings at the end of the study period (summer 2025).

The sections of circuit explicitly over their ratings are: Seaforth Jct. x Goshen Jct., and Goshen Jct. x Kirkton Jct. The emergency ratings of these sections are limited by substandard clearances due to ground topology and a rural distribution line. Due to the limited recorded effectiveness of CDM uptake in this Region, this thermal overload Need will require further study and will therefore be managed by Local Planning with the Region's study team.

6.1.4 230 kV and 115 kV Connection Facilities

A station capacity assessment was performed over the study period for the 230 kV and 115 kV transformer stations in the Region using the winter and summer station non-coincident peak load forecasts. All stations in the Region have adequate supply capacity for the study period (2016-2025).

6.2 System Reliability, Operation and Restoration Review

6.2.1 Load Security

Based on the gross regional-coincident peak load forecast, with all transmission facilities in-service and coincident with an outage of the largest local generation units, all facilities are within applicable ratings. The largest local generation unit is a 230 kV-connected Bruce nuclear unit on the 230 kV system while on the 115 kV system Goshen wind farm is assumed out of service.

Based on the gross regional-coincident load forecast, the loss of one element will not result in load interruption greater than 150 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Based on the gross regional-coincident load forecast, the loss of two elements will not results in load interruption greater than 600 MW by configuration, by planned load curtailment or by load rejection. In addition, under these conditions, all facilities are within their applicable ratings.

Therefore, load security criteria for the Region are met.

6.2.2 Load Restoration

Based on the gross regional-coincident peak load forecasts, with the use of existing transmission infrastructure, all load can be restored within approximately 8 hours depending on the severity of the contingency, the prevailing system conditions and the relative distance from the nearest field maintenance centre. Existing transmission infrastructure includes switches that can be operated from the Ontario Grid Control Centre (OGCC), Mid-Span Openers (MSOs) and other isolating devices that require a bucket truck and line crew to open and close.

The largest loss of load in the Region is 325 MW in winter 2024/2025 for the loss of the double circuit line B22D/B23D. By use of existing 61B22D-21 and 61B23D-26 switches at Seaforth TS, the OGCC can quickly resupply, within 30 minutes, approximately 218 MW from Bruce A TS or approximately 268 MW from Detwiler TS. The remaining load can be resupplied in 4-8 hours by opening existing bolted openers along the circuits.

Therefore, load restoration criteria for the Region are met.

6.2.3 Power Factor at Connection Facilities

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Wingham TS does not meet Market Rule requirements. Based on May 2014 to May 2015 historical data the power factor at Wingham TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point at least 60% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected LDCs.

Based on the analysis of historical power factors at connection facilities under peak load conditions, the power factor at Bruce HWP B TS does not meet Market Rule requirements. Based on January 2014 to December 2015 historical data the power factor at Bruce HWP B TS does not meet Market Rule requirement of 0.9 lead-lag power factor at the defined meter point approximately 80% of the time. This is a Need that will be managed by Local Planning between the transmitter and the affected customer.

6.2.4 Voltage Performance

Under winter 2020/2021 gross regional-coincident peak load conditions, post-contingency voltage at the Wingham TS 44 kV bus is below 6% of nominal voltage and may result is poor end-of-feeder voltages. Under winter *net* regional-coincident peak load conditions, the need is deferred by two years to winter 2022/2023. This is a Need that requires mitigation via Local Planning between the transmitter and the affected LDCs.

6.2.5 Customer Delivery Point Performance

Based on a review of Hydro One's historical delivery point performance statistics, several customer delivery points in the Region are below their historical measures. The delivery points are those fed from the Region's 115 kV system. These statistics are consistent with those provided by IESO. Mitigation measures that align with Hydro One's OEB approved process for addressing poor performance will be discussed between the transmitter and the affected LDCs and transmission customers.

6.2.6 Bulk Power System Performance in the Region

To bridge regional system planning with bulk system planning, a select number of bulk system planning contingencies within the Region are undertaken. With respect to the 230 kV circuits that supply regional load, breaker failure contingencies of these circuit's terminal breakers at BES and BPS station are analyzed to determine their impact. Gross regional-coincident peak load for the Greater Bruce-Huron region was used while a net regional-coincident peak load forecast for the KWCG region was used.

The results showed that 230 kV transmission circuit D7V between Detweiler TS and Waterloo North Junction is at its thermal rating at the end of the study period. This result is consistent with KWCG Regional Infrastructure Plan findings.

As recommended in the KWCG RIP, this Needs Assessment also recommends further investigation via bulk system planning study.

6.3 Aging Infrastructure and Replacement Plan of Major Equipment

Table 3 lists Hydro One transmission sustainment initiatives that are currently planned for aging and End-Of-Life (EOL) infrastructure.

Table 3: Hydro One Transmission Sustainment Initiatives

Station/Circuit	Description of Work	Planning In-Service Date
Bruce A TS	230 kV breaker replacement	2019
	500 kV breaker replacement	2024
Bruce B SS	500 kV breaker replacement	2020
Goderich TS	Station refurbishment: replace existing 3 transformers (T1/T2/T3) with a typical 50/83 MVA 2 transformer DESN arrangement (T4/T5)	2017
Detweiler TS	Replace AC station service	2017
	Replace T2 and T4 autotransformers	2021
Centralia TS	Station refurbishment: replace existing 3 transformers with a typical 25/42 MVA 2	2018

	transformer DESN arrangement	
Palmerston TS	Station refurbishment: replace existing 3 transformers with a typical 50/83 MVA 2 transformer DESN arrangement	2018
Wingham TS	Station refurbishment	2022
Seaforth TS	Station refurbishment: to include autotransformers and DESN	2023
Hanover TS	Station refurbishment: to include DESN	2023
Stratford TS	Station refurbishment	2023
Circuit L7S	Replacement of 4 wood poles	2016
	Insulator replacements	As required
Circuit S1H	Replacement of shield wire	2016
	Replacement of 9 wood poles	2017
Circuits B4V & B5V	Insulator and U-bolt replacement	As required
Circuits B22D & B23D	Insulator replacements	As required
Circuits B27S & B28S	Insulator replacements	As required
Circuits B20P & B24P	Insulator replacements	As required

The replacement and/or refurbishment of equipment may improve the overall reliability performance at customer delivery points. Further investigation is required to verify.

6.4 Planned Transmission and Distribution Investments

Listed in Table 4 are planned transmission and distribution investments in the Region. Note that other than the currently planned refurbishment work in table 3, Hydro One transmission does not have additional planned investments within the Region other than connecting generation upon request.

Table 4: Planned Local Distribution Company Investments

LDC	Investment Description	Planning In-Service Date
Wellington North Power	Transfer ~50% of LDC's Mount Forest load fed from Hanover TS to Palmerston TS in 2016. A feeder extension (M2) from Palmerston TS will be used for this load transfer. This transfer has been incorporated into the Region's station load forecast.	2016

7 RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team's recommendations are as follows:

1. To mitigate poor power factor and to prevent against voltage deficiency at Wingham TS, Local Planning between Hydro One transmission and Hydro One distribution (this may include additional LDC's embedded within Hydro One distribution fed out of Wingham TS) is recommended.

2. To mitigate poor power factor at Bruce HWP B TS, Local Planning between Hydro One transmission and the transmission connected customer is recommended.

3. To mitigate poor delivery point performance to several 115 kV connected customers, planning in accordance with Hydro One's OEB-approved process between Hydro One transmission, Hydro One distribution, Goderich Hydro and transmission connected customers is recommended.

4. To prevent against thermal overload on circuit L7S, Local Planning between Hydro One transmission and the Region's study team is recommended.

8 REFERENCES

i) Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario – May 17, 2013

ii) IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

9 ACRONYMS

BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Planning
kV	Kilovolt
LDC	Local Distribution Company
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low-voltage
MW	Megawatt
MVA	Mega Volt-Ampere
NERC	North American Electric Reliability Corporation
NA	Needs Assessment
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Planning
SIA	System Impact Assessment
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
ULTC	Under Load Tap Changer

APPENDIX A: LOAD FORECASTS

Table A1: Gross – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.87	33.40	33.77	34.25	34.87	35.48	35.93	36.36	36.77	37.19
Constance DS	17.58	17.68	17.76	17.79	17.87	18.01	18.16	18.26	18.35	18.46	18.57
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.41	19.55	19.70	19.85	20.00	20.15	20.30	20.45	20.60	20.76
Goderich TS	36.21	36.35	36.50	36.59	36.73	36.92	37.11	37.25	37.37	37.49	37.61
Grand Bend East DS	14.11	14.22	14.36	14.43	14.55	14.72	14.89	15.00	15.09	15.19	15.28
Hanover TS	101.59	102.37	103.16	103.93	104.95	105.99	107.05	107.73	108.39	109.06	109.72
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	60.95	61.92	62.92	63.88	65.12	66.22	67.44	68.42	69.41	70.41	71.40
Seaforth TS	33.27	33.44	33.65	33.78	33.97	34.22	34.47	34.64	34.80	34.95	35.10
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.64
St. Marys TS	23.48	23.74	25.04	25.17	25.31	25.50	25.69	25.84	25.98	26.12	26.25
Stratford TS	79.16	79.78	80.45	81.03	81.67	82.41	83.14	83.76	84.37	84.98	85.59
Wingham TS	48.21	48.99	49.80	50.44	51.23	52.24	53.24	54.07	54.89	55.74	56.62
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A2: Gross – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.42	32.73	33.15	33.78	34.40	34.83	35.24	35.65	36.05	36.45
Constance DS	15.47	15.56	15.57	15.63	15.76	15.90	15.98	16.07	16.16	16.26	16.36
Douglas Point TS	45.48	45.81	45.81	46.11	46.56	47.04	47.41	47.78	48.16	48.51	48.90
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	25.03	25.22	25.41	25.60	25.79	25.98	26.18	26.37	26.57	26.77
Goderich TS	38.95	39.08	39.15	39.27	39.48	39.68	39.81	39.93	40.06	40.18	40.31
Grand Bend East DS	16.32	16.44	16.50	16.62	16.84	17.05	17.17	17.29	17.39	17.50	17.61
Hanover TS	76.22	76.71	76.94	77.62	78.60	79.25	79.71	80.12	80.53	80.93	81.32
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	97.58	98.48	99.75	101.70	103.59	104.89	106.11	107.31	108.48	109.63
Palmerston TS	52.00	53.07	53.79	54.90	56.36	57.68	58.81	59.97	61.19	62.43	63.75
Seaforth TS	30.53	30.68	30.77	30.91	31.14	31.35	31.50	31.63	31.14	31.90	32.03
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.31	25.42	25.57	25.75	25.94	26.09	26.24	26.38	26.52	26.66
Stratford TS	77.16	77.76	78.26	78.86	79.62	80.38	80.98	81.57	82.16	82.74	83.32
Wingham TS	37.69	37.99	38.11	38.36	38.87	39.37	39.67	39.97	40.26	40.54	40.83
Bruce HWB TS	5.05	5.14	5.24	5.34	5.44	5.54	5.64	5.74	5.84	5.93	6.03

* Summer 2014

** Summer 2013

Table A3: Gross – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	34.15	34.70	35.08	35.59	36.23	36.87	37.33	37.77	38.21	38.63
Constance DS	18.63	19.42	19.51	19.54	19.63	19.79	19.95	20.06	20.17	20.28	20.40
Douglas Point TS	70.95	71.97	72.93	73.75	74.76	75.95	77.17	78.29	79.41	80.58	81.80
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	25.47	25.66	25.85	26.05	26.24	26.44	26.64	26.84	27.04	27.24
Goderich TS	40.95	41.61	41.78	41.88	42.04	42.26	42.48	42.63	42.77	42.91	43.05
Grand Bend East DS	14.63	14.75	14.89	14.97	15.09	15.27	15.45	15.56	15.66	15.75	15.85
Hanover TS	102.64	96.65*	97.40	98.12	99.09	100.07	101.06	101.71	102.33	102.97	103.58
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	133.69	135.53	137.73	139.21	141.20	143.81	146.38	148.20	149.90	151.56	153.19
Palmerston TS	61.48	68.03*	69.12	70.18	71.54	72.76	74.10	75.17	76.26	77.36	78.45
Seaforth TS	33.69	34.75	34.96	35.10	35.29	35.55	35.81	35.99	36.15	36.31	36.47
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	25.13	26.50	26.64	26.79	26.99	27.19	27.35	27.50	27.64	27.78
Stratford TS	83.48	84.52	85.23	85.84	86.52	87.30	88.08	88.74	89.39	90.03	90.68
Wingham TS	57.06	57.98	58.94	59.70	60.63	61.82	63.01	63.98	64.96	65.96	67.00
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A4: Gross – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	34.23	34.56	35.01	35.67	36.32	36.78	37.22	37.64	38.07	38.49
Constance DS	17.69	17.78	17.79	17.86	18.01	18.17	18.27	18.36	18.47	18.58	18.70
Douglas Point TS	46.11	46.44	46.45	46.75	47.21	47.69	48.07	48.45	48.83	49.19	49.58
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	28.11	28.32	28.53	28.74	28.96	29.18	29.39	29.61	29.84	30.06
Goderich TS	39.27	40.71	40.78	40.91	41.12	41.33	41.46	41.59	41.72	41.85	41.98
Grand Bend East DS	18.74	18.88	18.95	19.09	19.34	19.58	19.72	19.85	19.98	20.10	20.22
Hanover TS	76.22	75.61*	75.84	76.50	77.47	78.12	78.57	78.97	79.37	79.77	80.15
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.01	101.31	102.25	103.57	105.59	107.55	108.90	110.17	111.41	112.63	113.82
Palmerston TS	52.32	54.71*	55.45	56.60	58.10	59.46	60.63	61.82	63.07	64.36	65.72
Seaforth TS	30.53	31.00	31.09	31.24	31.46	31.68	31.83	31.96	31.47	32.24	32.37
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	26.05	26.17	26.31	26.51	26.70	26.86	27.01	27.16	27.30	27.44
Stratford TS	86.43	88.42	88.99	89.68	90.54	91.40	92.09	92.76	93.43	94.09	94.75
Wingham TS	50.74	54.05	54.21	54.58	55.29	56.00	56.43	56.86	57.27	57.67	58.08
Bruce HWB TS	6.42	6.54	6.66	6.79	6.91	7.04	7.16	7.29	7.42	7.54	7.67

*Load Transfer from Hanover TS to Palmerston TS

Table A5: Net – Winter Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	32.42	32.65	32.92	32.96	33.16	33.52	33.90	34.16	34.45	34.69	34.94
Constance DS	17.58	17.57	17.55	17.41	17.35	17.36	17.40	17.41	17.44	17.46	17.50
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	0.89*	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90
Festival MTS #1	19.26	19.29	19.33	19.29	19.27	19.28	19.31	19.36	19.43	19.49	19.56
Goderich TS	36.21	36.12	36.07	35.81	35.65	35.58	35.55	35.50	35.49	35.45	35.43
Grand Bend East DS	14.11	14.13	14.19	14.13	14.13	14.19	14.27	14.30	14.34	14.37	14.39
Hanover TS	101.59	101.72	101.94	101.69	101.76	102.01	102.42	102.56	102.84	103.02	103.23
Customer CTS #2	4.27**	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30	4.30
Customer CTS #3	1.93**	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	60.95	61.53	62.17	62.50	63.20	63.80	64.60	65.20	65.92	66.58	67.25
Seaforth TS	33.27	33.24	33.26	33.06	32.98	32.98	33.02	33.02	33.06	33.06	33.07
Customer CTS #4	9.37	9.49	10.07	10.07	10.64	10.64	10.64	10.64	10.64	10.64	10.65
St. Marys TS	23.48	23.59	24.75	24.63	24.57	24.58	24.61	24.63	24.68	24.70	24.73
Stratford TS	79.16	79.30	79.52	79.30	79.29	79.42	79.65	79.86	80.16	80.39	80.64
Wingham TS	48.21	48.70	49.23	49.38	49.75	50.36	51.02	51.55	52.16	52.73	53.35
Bruce HWB TS	10.95	10.96	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10	11.10

* Winter 2013/14

** Winter 2012/13

Table A6: Net – Summer Regional-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	32.00	32.04	31.57	31.62	31.89	32.20	32.42	32.61	32.85	33.05	33.25
Constance DS	15.47	15.45	15.35	15.23	15.20	15.20	15.19	15.18	15.20	15.22	15.24
Douglas Point TS	45.48	45.43	45.11	44.89	44.87	44.93	45.02	45.10	45.26	45.35	45.49
Customer CTS #1	1.29*	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30	1.30
Festival MTS #1	24.84	24.85	24.86	24.77	24.69	24.66	24.70	24.74	24.82	24.87	24.93
Goderich TS	38.95	38.70	38.50	38.18	37.98	37.84	37.74	37.63	37.59	37.50	37.43
Grand Bend East DS	16.32	16.32	16.27	16.20	16.24	16.31	16.33	16.33	16.37	16.38	16.40
Hanover TS	76.22	75.82	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58	5.58
Customer CTS #3	4.17**	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20	4.20
Owen Sound TS	96.32	96.71	96.49	96.54	97.40	98.36	99.01	99.56	100.27	100.83	101.40
Palmerston TS	52.00	52.48	52.81	53.30	54.15	54.94	55.69	56.45	57.35	58.21	59.16
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	14.42	14.62	15.54	15.54	16.47	16.47	16.47	16.47	16.47	16.47	16.47
St. Marys TS	25.16	25.07	25.01	24.87	24.79	24.76	24.75	24.74	24.77	24.77	24.78
Stratford TS	77.16	77.10	77.05	76.77	76.70	76.76	76.87	76.97	77.20	77.33	77.49
Wingham TS	37.69	37.72	37.57	37.40	37.49	37.65	37.71	37.76	37.88	37.94	38.03
Bruce HWB TS	5.05	5.06	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12	5.12

* Summer 2014

** Summer 2013

Table A7: Net – Winter Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Centralia TS	33.69	33.93	34.20	34.24	34.46	34.82	35.23	35.50	35.79	36.05	36.31
Constance DS	18.63	18.62	18.61	18.45	18.39	18.40	18.44	18.45	18.48	18.51	18.55
Douglas Point TS	70.95	71.54	72.09	72.19	72.59	73.20	73.94	74.64	75.45	76.23	77.08
Customer CTS #1	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79
Festival MTS #1	23.79	23.83	23.87	23.82	23.80	23.81	23.84	23.90	24.00	24.07	24.16
Goderich TS	40.95	40.85	40.79	40.49	40.32	40.23	40.20	40.15	40.14	40.09	40.06
Grand Bend East DS	14.63	14.66	14.72	14.65	14.65	14.72	14.81	14.84	14.88	14.90	14.93
Hanover TS	102.64	102.77*	102.99	102.75	102.81	103.07	103.48	103.63	103.90	104.09	104.30
Customer CTS #2	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Customer CTS #3	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63	4.63
Owen Sound TS	133.69	134.70	136.07	136.18	137.02	138.53	140.18	141.21	142.35	143.29	144.25
Palmerston TS	61.48	62.06*	62.70	63.04	63.75	64.36	65.15	65.77	66.49	67.16	67.83
Seaforth TS	33.69	33.66	33.68	33.48	33.39	33.40	33.44	33.44	33.47	33.47	33.49
Customer CTS #4	16.84	17.06	18.10	18.10	19.14	19.14	19.14	19.14	19.14	19.14	19.14
St. Marys TS	24.84	24.97	26.19	26.07	26.01	26.01	26.04	26.07	26.12	26.14	26.17
Stratford TS	83.48	83.62	83.86	83.63	83.62	83.75	84.00	84.21	84.53	84.77	85.04
Wingham TS	57.06	57.64	58.26	58.44	58.87	59.59	60.38	61.01	61.73	62.41	63.14
Bruce HWB TS	11.05	11.07	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20	11.20

*Load Transfer from Hanover TS to Palmerston TS

Table A8: Net – Summer Non-Coincident Peak Load Forecast

Station	Historical (MW)	Forecast (MW)									
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Centralia TS	33.79	33.84	33.38	33.43	33.72	34.04	34.27	34.47	34.72	34.93	35.15
Constance DS	17.69	17.66	17.54	17.41	17.37	17.38	17.36	17.35	17.38	17.39	17.42
Douglas Point TS	46.11	46.06	45.74	45.52	45.49	45.56	45.65	45.72	45.89	45.98	46.13
Customer CTS #1	2.53	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00	3.00
Festival MTS #1	27.90	27.91	27.92	27.81	27.73	27.69	27.74	27.77	27.87	27.93	28.00
Goderich TS	39.27	39.02	38.81	38.49	38.29	38.15	38.05	37.93	37.89	37.81	37.74
Grand Bend East DS	18.74	18.75	18.68	18.61	18.65	18.73	18.75	18.76	18.80	18.81	18.83
Hanover TS	76.22	75.82*	75.51	75.32	75.37	75.34	75.33	75.25	75.32	75.30	75.29
Customer CTS #2	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79	5.79
Customer CTS #3	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53	4.53
Owen Sound TS	100.01	100.41*	100.21	100.26	101.16	102.15	102.82	103.40	104.13	104.72	105.31
Palmerston TS	52.32	52.80	53.13	53.63	54.48	55.27	56.03	56.79	57.70	58.57	59.52
Seaforth TS	30.53	30.39	30.27	30.06	29.96	29.91	29.87	29.82	29.23	29.79	29.76
Customer CTS #4	16.00	16.22	17.24	17.24	18.27	18.27	18.27	18.27	18.27	18.27	18.27
St. Marys TS	25.90	25.81	25.74	25.60	25.52	25.49	25.48	25.47	25.50	25.50	25.50
Stratford TS	86.43	86.36	86.31	86.00	85.92	85.99	86.12	86.22	86.48	86.63	86.81
Wingham TS	50.74	50.79	50.58	50.35	50.48	50.69	50.77	50.84	51.00	51.08	51.20
Bruce HWB TS	6.42	9.83	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95	9.95

*Load Transfer from Hanover TS to Palmerston TS

ASSESSMENT OF LOW POWER FACTOR AT BRUCE HEAVY WATER B TS

Date: May 12th, 2017

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Background

As part of the Ontario Energy Board's (OEB) Regional Planning process, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region, one of them being the poor power factor at Bruce Heavy Water B (Bruce HWB) TS.

This assessment addresses the low power factor issues at the Bruce HWB TS identified in the Needs Assessment report.

Introduction

Bruce HWB TS is a 230/13.8kV transformer station supplying one transmission-connected customer, Bruce Power's loads. The station is supplied via 230kV circuits B20P and B24P and has an approximate loading of 10MW. There is no distributed generation (DG) connected at Bruce HWB TS.

As per IESO Market Rules, customers are required to maintain a power factor of 0.9 or better at the point of connection. From the data gathered for the Needs Assessment phase it was observed, from January 2014 to December 2015, that the power factor fell below the 0.9 requirement 80% of the time.

Findings

Upon further assessment, Hydro One reached out to Bruce Power (the Customer) to determine if the Customer had similar issues or concerns with the power factor at the point of connection. The Customer's metering data showed an average power factor of 0.91 from August 2014 to November 2016, varying from as low as 0.724 on occasion, up to a very healthy 0.975.

The Customer's metered data differed significantly from the IESO's telemetered data that was used for the Needs Assessment. To verify the discrepancy, historical data was requested from Hydro One's settlements department. Upon analyzing the Hydro One settlements data, Hydro One found that the power factor performance at Bruce HWB was very good, with a similar average and range to the power factor calculated from the Customer's data. From January 2015 to August 2016 the power factor was above 0.9 for almost 60% of the time, and above 0.85 more than 95% of the time. Graphs representing the power factor data and the power factor performance are shown in Figures 1 and 2, respectively, in Appendix A.

Even with the occasional dip to the mid-0.7 range, the Customer indicated that it believes that power factor at the point of connection is good, and that it is satisfied with the power quality that is being supplied to its loads. The station load at Bruce HWB TS is well below the station's capacity, and there are no concerns about equipment overloading or being damaged. It was also confirmed that both the 230kV and the 13.8kV bus voltage stayed within criteria during periods of low power factor.

Conclusion

The power factor at Bruce HWB TS is generally above 0.85. Since there are no voltage issues at Bruce HWB TS and there is no lack of reactive power support in the local area, Hydro One Transmission, IESO and Bruce Power propose that no action is required at this time and the occasional low power factor observed at Bruce HWB TS is not a need that requires mitigation. Hydro One will continue to monitor the situation and act accordingly if the low power factor becomes an issue in the future.

APPENDIX A

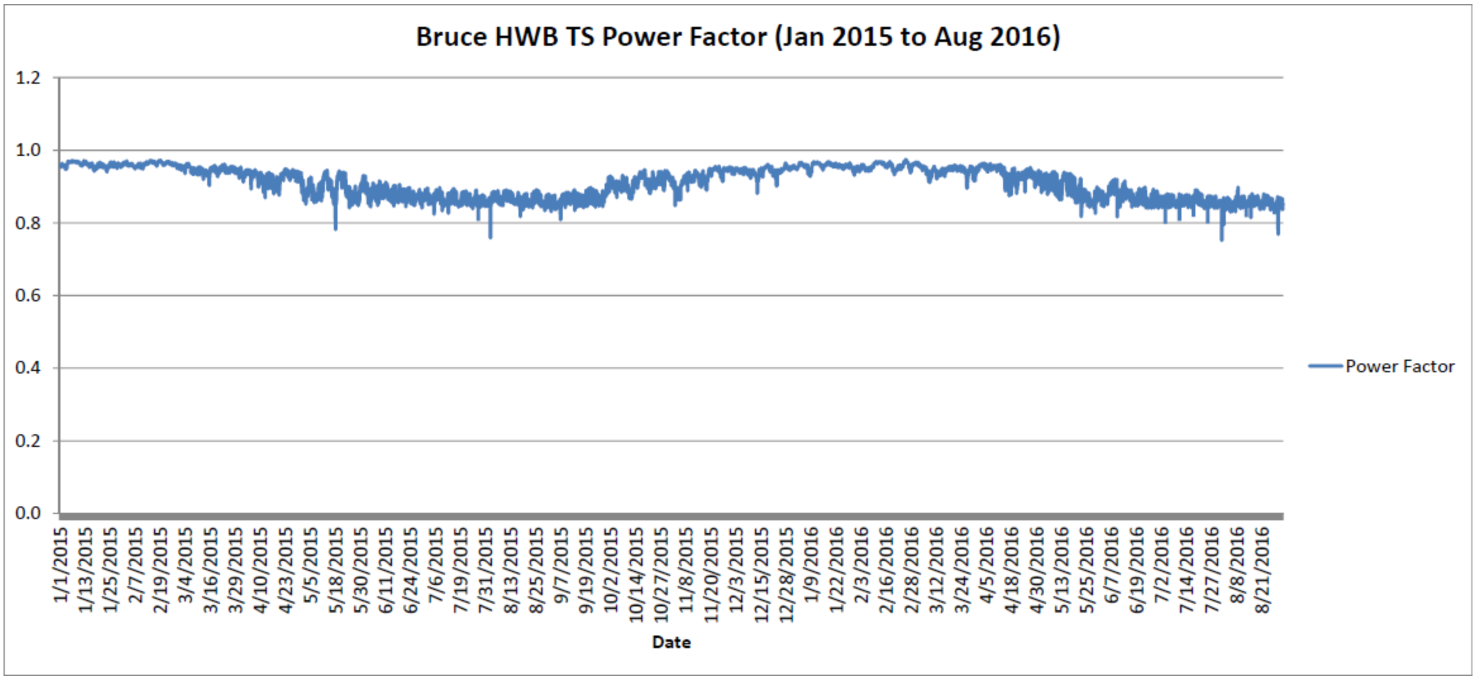

Figure 1: Graph showing the power factor at Bruce HWB TS between January 2015 and August 2016.

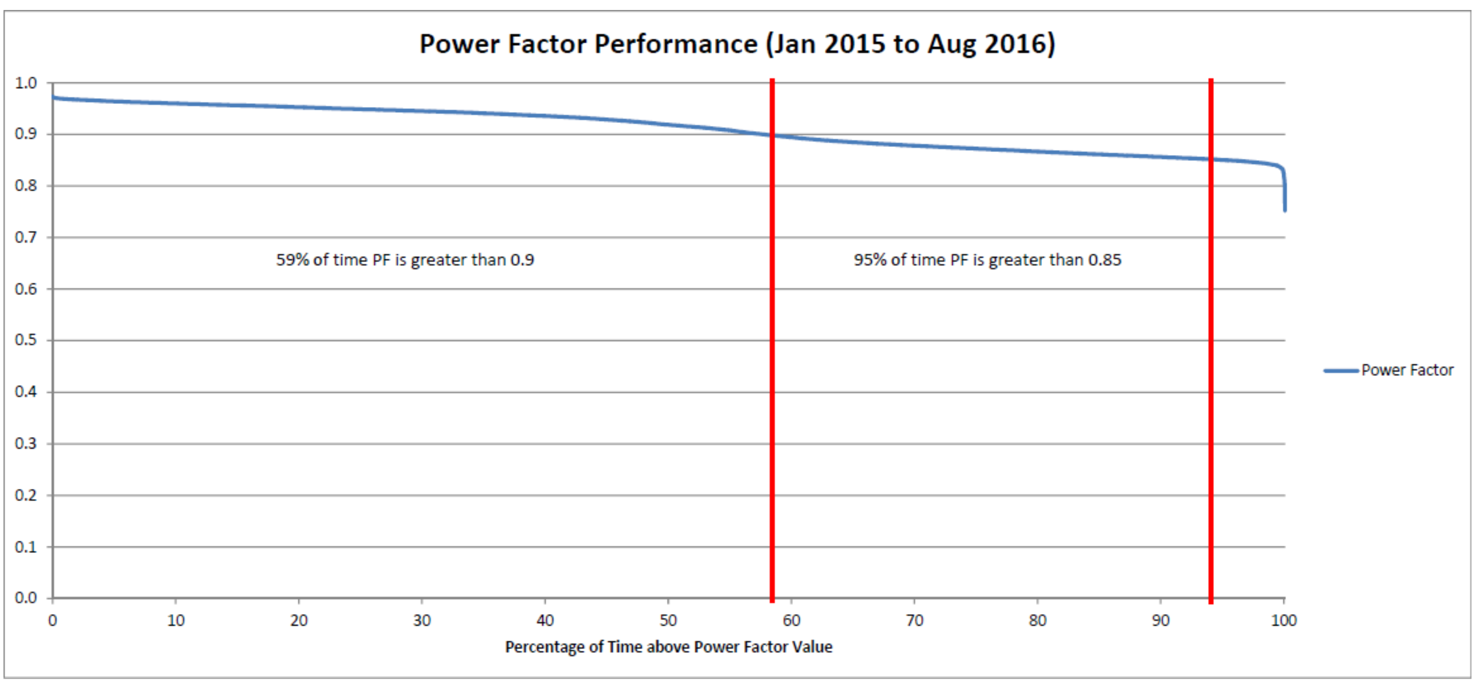

Figure 2: Graph showing power factor performance at Bruce HWB TS between January 2015 and August 2016.

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LOCAL PLANNING REPORT

L7S Thermal Overload
Region: Greater Bruce - Huron

Date: November 14, 2016
Revision: Final

This report is prepared on behalf of the study team with the participation of representatives from the following organizations:

Distribution

Transmission

Disclaimer

This Local Planning Report was prepared for the purpose of developing transmission and distribution options and recommending a preferred solution(s) to address the local needs identified in the Needs Assessment for the Greater Bruce/Huron Region that do not require further coordinated regional planning. The preferred solution(s) that have been identified through this Local Planning Report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this Local Planning Report are based on the information and assumptions provided by study team participants.

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EXECUTIVE SUMMARY

REGION	Greater Bruce-Huron Region (the "Region")		
LEAD	Hydro One Networks Inc. ("Hydro One")		
START DATE	May 18, 2016	**END DATE**	November 14, 2016

1. INTRODUCTION

The purpose of this Local Planning ("LP") report is to evaluate options and develop a Plan to mitigate the thermal overload on circuit L7S as identified in the Greater Bruce-Huron Regional Planning Needs Assessment report (Needs Assessment).

2. THE NEED

Based on the Region's gross load forecast, circuit L7S will become loaded beyond both its Short-Term Emergency (STE) and Long-Term Emergency (LTE) ratings in year 2019. Utilizing the Region's net load forecast, the Need is deferred to year 2025. Due to the limited recorded effectiveness of Conservation and Demand Management (CDM) uptake in this Region, identification of a mitigation Plan was deemed prudent.

3. OPTIONS EVALUATED

The following options were evaluated:

- Option 1: Status Quo and Monitor Load Growth
- Option 2: Increase L7S Circuit Ratings
- Option 3: Load Transfer –> Pre-contingency control action
- Option 4: Load Rejection + Load Transfer –> Post-contingency control actions

4. PREFERRED SOLUTION

Option 1 is the preferred option. As the summer 2016 historical load was substantially lower that the forecasted 2016 load the status quo and monitor load growth option is deemed the most prudent in order to defer costs. The Region will continue to monitor load growth and when required, the preferred option to mitigate the thermal overload on circuit L7S is Option 2: Increase L7S Circuit Ratings.

5. RECOMMENDATIONS

The recommended Plan to mitigate the thermal overload on circuit L7S is:

Step 1 Review historical load and flow on circuit L7S after each summer and winter season

Step 2 When historical station load supplied by L7S reaches 99 MW or historical flow on L7S reaches 94% of the circuit's ampacity rating, refresh gross load forecast

Step 3 When refreshed gross load forecast indicates 105 MW of station load supplied by L7S OR simulated flow on L7S will reach 100% of the circuit's ampacity rating within the next 3 years proceed to increase circuit ratings. Capacity cost allocation will be as per the Transmission System Code.

Provided the station load and/or circuit flow meets the predetermined MW or % thresholds within the specified timeframe, the Plan can be implemented prior to subsequent cycles of Regional Planning. If the Plan is not already under implementation, it is to be reviewed and reaffirmed in subsequent cycles of Regional Planning.

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1.0 Introduction

As part of the Ontario Energy Board's (OEB) Regional Planning requirements, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region (Needs Assessment), one of them being the thermal overload on circuit L7S.

The purpose of this Local Planning assessment is to evaluate options and develop a Plan to mitigate the thermal overload on circuit L7S.

1.1 Description of Need

Figure 1 illustrates 115 kV circuit L7S runs between Seaforth Transformer Station (TS) and St. Marys TS and is connected to 115 kV circuit D8S that runs between St. Marys TS and Detweiler TS, through the St. Marys TS low voltage bus-tie breaker. For the loss of D8S, L7S will exceed its short-term emergency (STE) and long-term emergency (LTE) ratings in the near term (summer 2019), under summer *gross* peak load conditions. Under summer *net* peak load conditions, the flow on L7S decreases to ~97% of its emergency ratings at the end of the study period (summer 2025). Table 1 is the amount of forecasted load supplied from circuit L7S when circuit D8S is unavailable. The forecast is as per the 2016 Needs Assessment for the Region.

The segments of circuit explicitly over their ratings are a few spans within the Seaforth Junction x Goshen Junction x Kirkton Junction sections. The emergency ratings of these spans are limited by substandard clearances due to ground topology and a rural distribution line. Due to the limited recorded effectiveness of Conservation and Demand Management (CDM) uptake in this Region, identification of a mitigation plan for the thermal overload is deemed prudent.

2.0 Options to Address the Need

Several options were considered in order to address the L7S thermal overload need. Table 2 lists and describes each option. There are several measures that can be utilized to compare and evaluate options. Measures utilized in this analysis were estimated cost, required approvals, long-term benefits and impact to customers. These measures were deemed most important in order to select the preferred option(s).

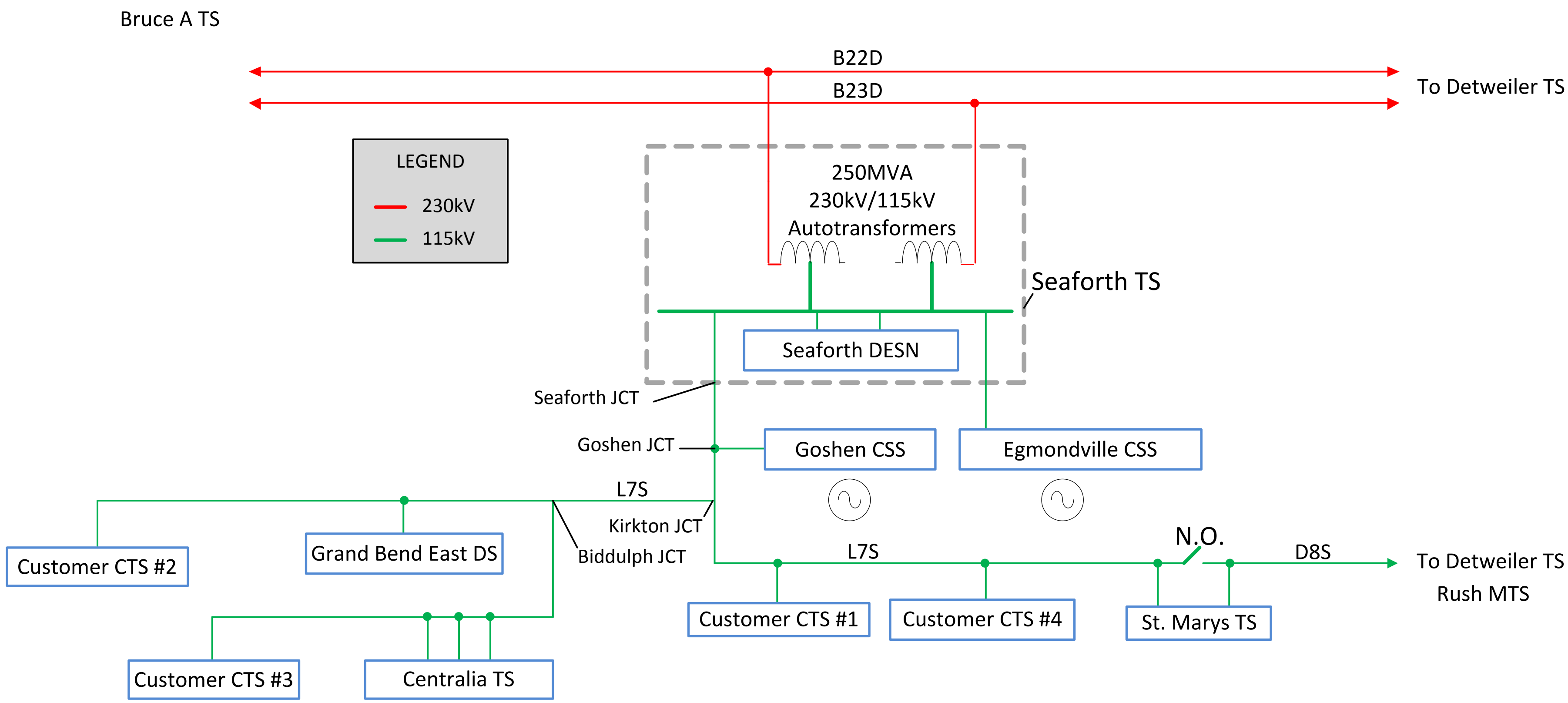

Figure 1 – Single Line Diagram of circuit L7S

Table 1 – Regional-Coincident Summer Peak Load Forecast supplied by circuit L7S[1]

Type of Forecast	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Total Gross Load on L7S [MW]	100	101	102	104	105	106	106	107	108	108
Total Net Load on L7S [MW]	99	99	99	100	101	101	101	102	102	102

[1] For the loss of circuit D8S, the following stations are supplied from circuit L7S: Centralia TS, Grand Bend East DS, St. Marys TS, Customer CTS #1, Customer CTS #2, Customer CTS #3 and Customer CTS #4. The forecast is a summation of the forecasted station loading. Actual flow on circuit L7S would be the summation of station load with it respective power factor plus line losses.

Table 2 – Options to Address the L7S Thermal Overload

Options		Description	Cost[2]	Required Approvals	Long-Term Benefits	Impact to Customers
1	Status Quo & Monitor Load Growth	Monitor load growth and CDM targets; when historical load approaches the forecasted load proceed with mitigation; see Figure 2: Load Growth at Stations Supplied by Circuit L7S	0	None	Defers costs until forecasted load begins to materialize.	None provided load growth is closely monitored to ensure mitigation is in place before the Need arise.
2	Increase L7S Circuit Ratings	Uprate limiting sections of the circuit to have emergency ratings that can accommodate the forecasted load; Increase the maximum sag temperature from 83°C to 110°C. Initial assessment indicates 3 spans require tower replacements and/or modifications.	$550 k	Environmental Approval Screen-out	Uprating will improve continuous and emergency ratings to accommodate the 10 year load forecast; no voltage issues with 10 year load forecast	A temporary outage during the construction of the project may be required; otherwise there is no negative impact to customers.
3	Load Transfer: Pre-contingency control action	During peak L7S loading conditions, ~8.5 MW is required to be transferred off circuit L7S from Centralia TS to Seaforth TS over the distribution system via remote switching from Hydro One Distribution's "Modernized" Grid. However, the distribution system is capable of transferring only *4.4 MW* due to end-of-line voltage limitations.	$300 k	None	A 4.4 MW load transfer would only defer the Need for additional mitigation as the load grows. However depending on the pace of load growth, the 4.4 MW of load transfer may be enough to satisfy the 10 year study period.	There is reduced reliability to load that is transferred due to the increase in distribution line distance creating additional exposure to interruptions.
4	Load Rejection + Load Transfer: Post-contingency control actions	Implement a Load Rejection (L/R) scheme for the loss of circuit D8S. During peak L7S loading conditions, OGCC will arm the scheme. Upon loss of D8S, the armed load will be rejected / unsupplied. The L/R scheme will mitigate against the immediate overload of circuit L7S until such time as the load can be transferred from Centralia TS to Seaforth TS. At that time, the rejected load can be resupplied.	$500 k[3] - $700 k[4]	Load Rejection scheme may be classified as a Special Protection Scheme and require approval from NPCC	A 4.4 MW load transfer would only defer the Need for additional mitigation as the load grows. However depending on the pace of load growth, the 4.4 MW of load transfer may be enough to satisfy the 10 year study period.	There is risk to being unsupplied for load that is armed for rejection. There is also reduced reliability to load that is transferred due to the increase in distribution line distance creating additional exposure to interruptions.

[2] Costs are budgetary and of +/- 50% accuracy and do not include interest and overhead. Detailed estimate would be required prior to project execution.
[3] $400 k* for L/R scheme + $100 k for manual switching (2 hr.) = $500 k, *If load is to be rejected at stations other than St. Marys TS, additional telecom circuits are required (at a minimum) and this will increase the cost
[4] $400 k* for L/R scheme + $300 k for remote switching (15 min.) = $700 k, *If load is to be rejected at stations other than St. Marys TS, additional telecom circuits are required (at a minimum) and this will increase the cost

3.0 Discussion of the Preferred Options

Based on the forecasted load supplied by circuit L7S, the circuit will become overloaded for the loss of circuit D8S within the 10-year study period.

Of the four options, option #1 "Status Quo and Monitor Load Growth" is the preferred option to satisfy the Need as it will defer costs until the forecasted load begins to materialize. The 2016 summer coincident peak for stations supplied by circuit L7S occurred on August 10, 2016 and totaled 91.4 MW as shown in Figure 2. This loading translates to about 460 Amperes flow on circuit L7S between Seaforth TS and Kirkton Junction when circuit D8S is out of service which is approximately 87% of the circuit's rating (530 Amperes). In Figure 2, L7S's circuit rating is illustrated as 105 MW of total station load supplied by L7S.

Once the historical load begins to approach the thermal limit of the circuit, option #2 "Increase L7S Circuit Ratings", is the preferred option to mitigate against the overload. Option #2 is a permanent capacity improvement as opposed to ongoing control actions required with options #3 and #4. As well, option #2 does not place customer load at an increased risk to being unsupplied when armed for L/R (option #4) nor does it reduce customer reliability due to long distribution lines (options #3 & #4) and therefore it is the preferred option.

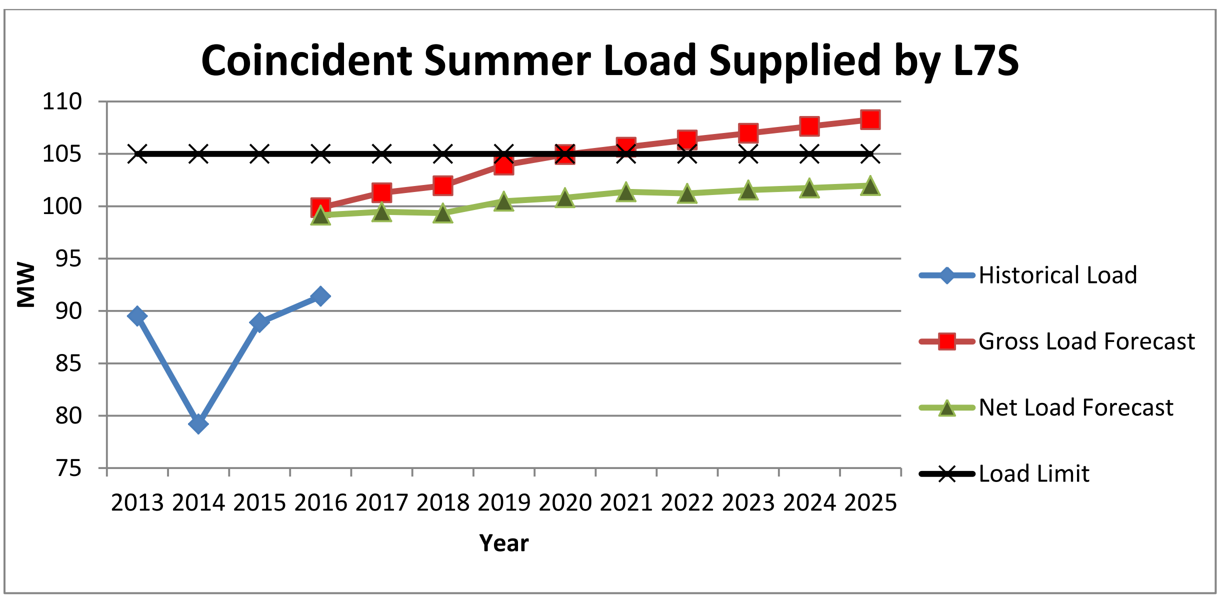

Figure 2 – Load Growth at Stations Supplied by Circuit L7S [5]

[5] The historical values and forecasts are a summation of station loading.

4.0 Development Plan

The transmission infrastructure development plan for the L7S thermal overload need is:

Step 1 Review coincident peak load on circuit L7S after each winter and summer season

- Action: IESO to provide historical data to Hydro One Transmission for review.

Step 2 Historical Load Analysis to determine if Trigger #1 met.

Trigger #1: when the historical load indicates that, for the loss of D8S, coincident peak station load supplied by circuit L7S reaches 99 MW OR historical flow on L7S out of Seaforth TS reaches 94% of the circuits' ampacity rating, a refreshed load forecast is to be provided by the LDC's and other connected customers.

- Action: Hydro One Transmission to review historical station load and flow; and when Trigger #1 is met, request a refreshed gross load forecast from LDC's and other connected customers.

- Action: LDC's and other connected customers to provide a refreshed gross load forecast within 45 days of the request to Hydro One Transmission.

Step 3 Load Forecast Analysis to determine if Trigger #2 met.

Trigger #2: when the refreshed gross load forecast indicates that, for the loss of D8S, coincident peak station loading of 105 MW is supplied by circuit L7S OR flow on L7S out of Seaforth TS reaches 100% of the circuits' ampacity rating within the next 3 years, Hydro One Transmission to proceed with mitigation.

- Action: Hydro One Transmission to review refreshed gross load forecast and flow; and if Trigger #2 is met, increase the thermal ratings of the limiting sections of circuit L7S. Capacity cost allocation will be as per the Transmission System Code.

The plan can be reviewed and reaffirmed in subsequent cycles of Regional Planning if not already under execution.

5.0 Recommendations

The following recommendations are to address the L7S thermal overload Need:

1. Continue to monitor load growth and refresh gross load forecasts according to the Development Plan outlined in Section 4.0.

2. When the loading on circuit L7S is expected to exceed its limits within the next 3 years, Hydro One Transmission to increase the thermal ratings of the limiting spans of circuit L7S. Capacity cost allocation will be as per the Transmission System Code.

LOW POWER FACTOR AT WINGHAM TS ASSESSMENT

Date: October 18th, 2016

Prepared and Reviewed by:

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Background

As part of the Ontario Energy Board's (OEB) Regional Planning process, a Needs Assessment was performed for the Greater Bruce / Huron Region. There were four (4) needs identified in the 2016 Needs Assessment for this Region, one of them being the poor power factor and voltage deficiency at Wingham TS.

This assessment addresses the low power factor and voltage deficiency issues at the Wingham TS identified in the Needs Assessment report.

Introduction

Wingham TS is a 230/44kV transformer station supplying Hydro One Distribution and Westario Power loads. The station is supplied via 230kV circuits B22D and B23D and has four (4) 44kV distribution feeders with an approximate loading of 60MW. There is also a significant amount of distributed generation (DG) connected at Wingham TS.

As per IESO Market Rules, customers are required to maintain a power factor of 0.9 or better at the point of connection. The power factor at Wingham TS has fallen below 0.5 on some occasions. A graph of the power factor performance at Wingham TS from June 2015 to June 2016 is shown in Figure 1 of Appendix A.

Findings

Upon further assessment, Hydro One Transmission, Hydro One Distribution and Westario Power determined that the low power factor was directly related to DGs connected on Hydro One's M4 feeder. The generation operates at a fixed power factor and is set to an appropriate value to help maintain the desired feeder voltage. DGs typically impact the load characteristic as seen from the transformer station. The DG will typically displace the loads real power (MW) absorbed from the transmission system while the reactive power (MVAr) of the load will typically remain unchanged.

To determine the root cause for low power factor, Hydro One Distribution and Westario Power investigated whether there were any loads that had undergone any facility modifications that could have caused this concern, however this was not the case. It was observed that, prior to the connection of an 18MW wind farm to a Wingham TS feeder, the power factor at the transformer station was consistently above 0.9, however the power factor started oscillating sporadically once the wind farm was placed in service. A graph showing the power factor performance before and after the incorporation of the wind farm is shown in Figure 2 of Appendix A.

To further confirm that it is the wind farm that is causing the poor power factor performance, the Wingham TS load power factor was isolated to determine if it would be acceptable without the effect of the 18MW wind farm. The wind farm's power output (MW and MVAr) was added to the Wingham TS load, and, the resulting load power factor was around 0.9. A graph showing the Wingham TS load power factor is shown in Figure 3 of Appendix A.

To ensure that the power factor performance was not negatively impacting the Wingham TS load customers, Hydro One Distribution and Westario Power looked into 1) customers' complaints about power quality (specifically voltage) and service, and 2) summer loading at Distribution Stations to confirm load power factors are acceptable. Neither Hydro One Distribution nor Westario Power received any customer complaints, and load power factors were found to be acceptable.

At this time, the Wingham TS load is well below the station's capacity, and therefore the higher MVA flow (caused by the absorption of VAR by the wind farm) will not result in equipment overload or cause equipment damage. It was also confirmed that both the 230kV and the 44kV bus voltage stayed within criteria during periods of low power factor. A graph of the Wingham TS MVA loading from May 2013 to May 2016 is shown in Figure 4 of Appendix A.

Conclusion

The power factor of loads at Wingham TS is within planning criteria, and the DGs connected at Wingham TS are the cause of the power factor deviating from Market Rules. Since there are no voltage issues at Wingham TS, and there is no lack of reactive power support in the local area, Hydro One Transmission, Hydro One Distribution and Westario Power propose that no action is required at this time and the occasional low power factor observed at Wingham TS is not a need that requires mitigation. Hydro One proposes to discuss, with the IESO, possible changes to the Market Rules that would take into account the effects DGs have on station power factor, and will continue to monitor the situation and act accordingly if the low power factor becomes an issue in the future.

APPENDIX A

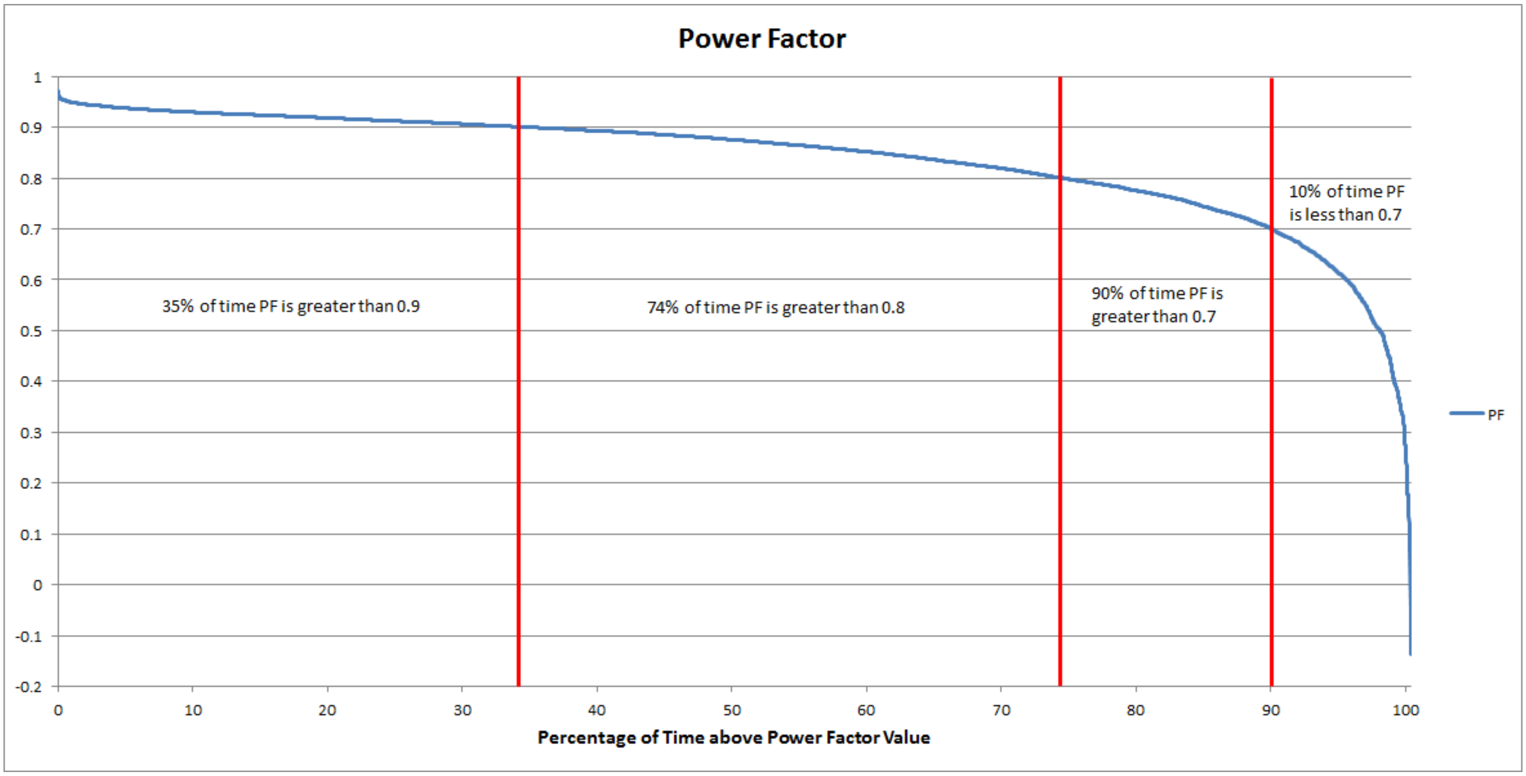

Figure 1: Graph showing the power factor performance ot Wingham TS between June 2015 and June 2016

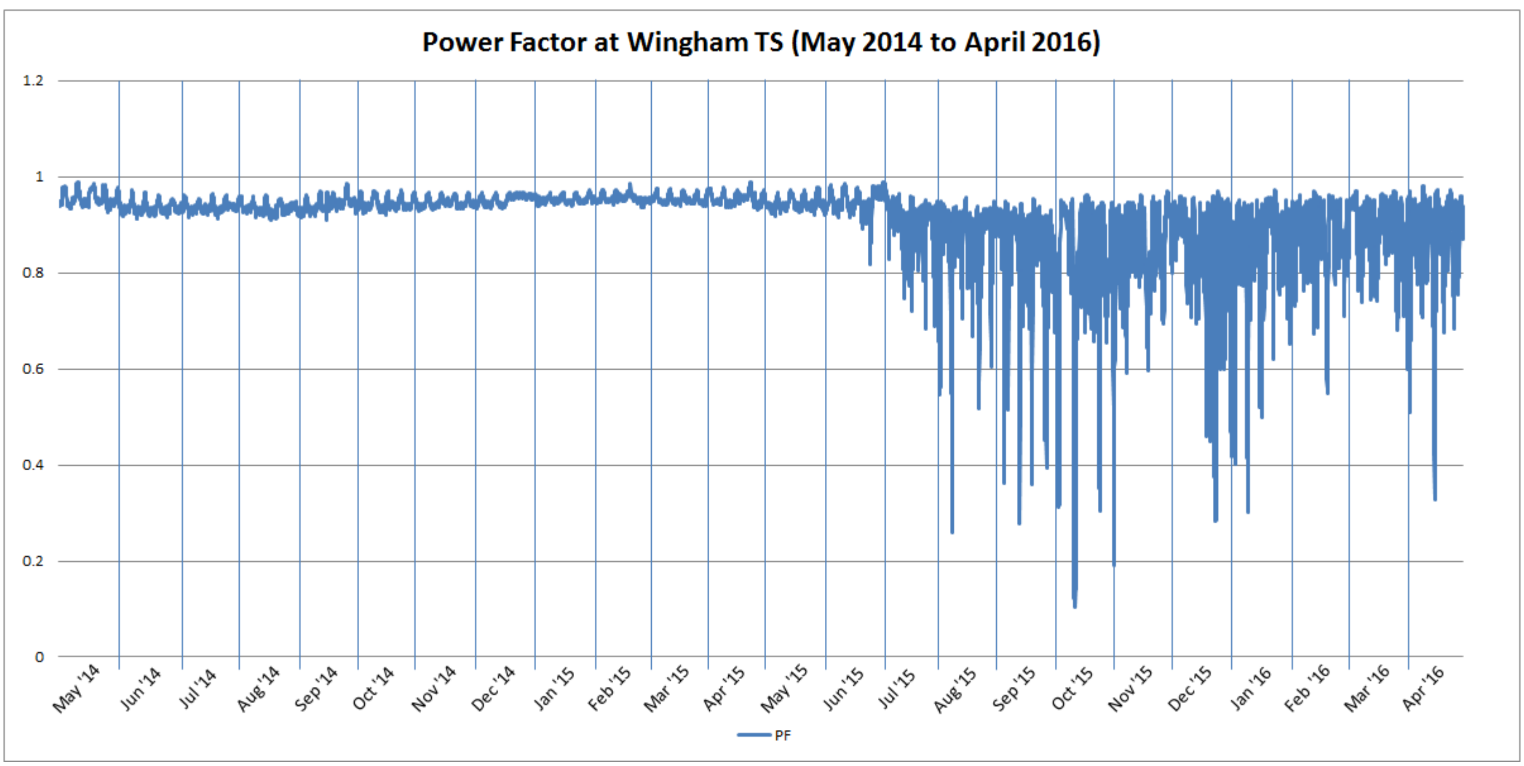

Figure 2: Graph showing Wingham TS power factor before and after wind farm was place in service.

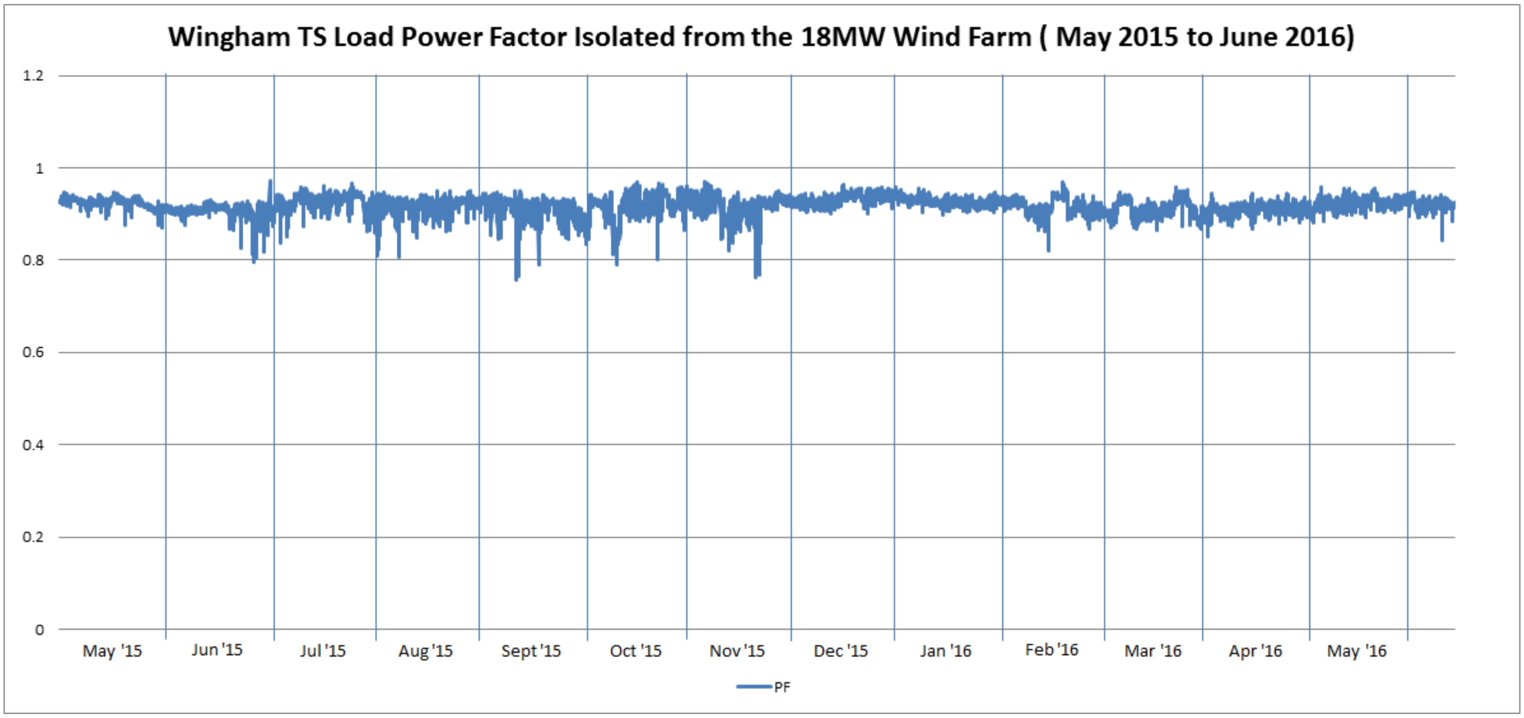

Figure 3: Graph showing Wingham TS load power factor since the connection of wind farm.

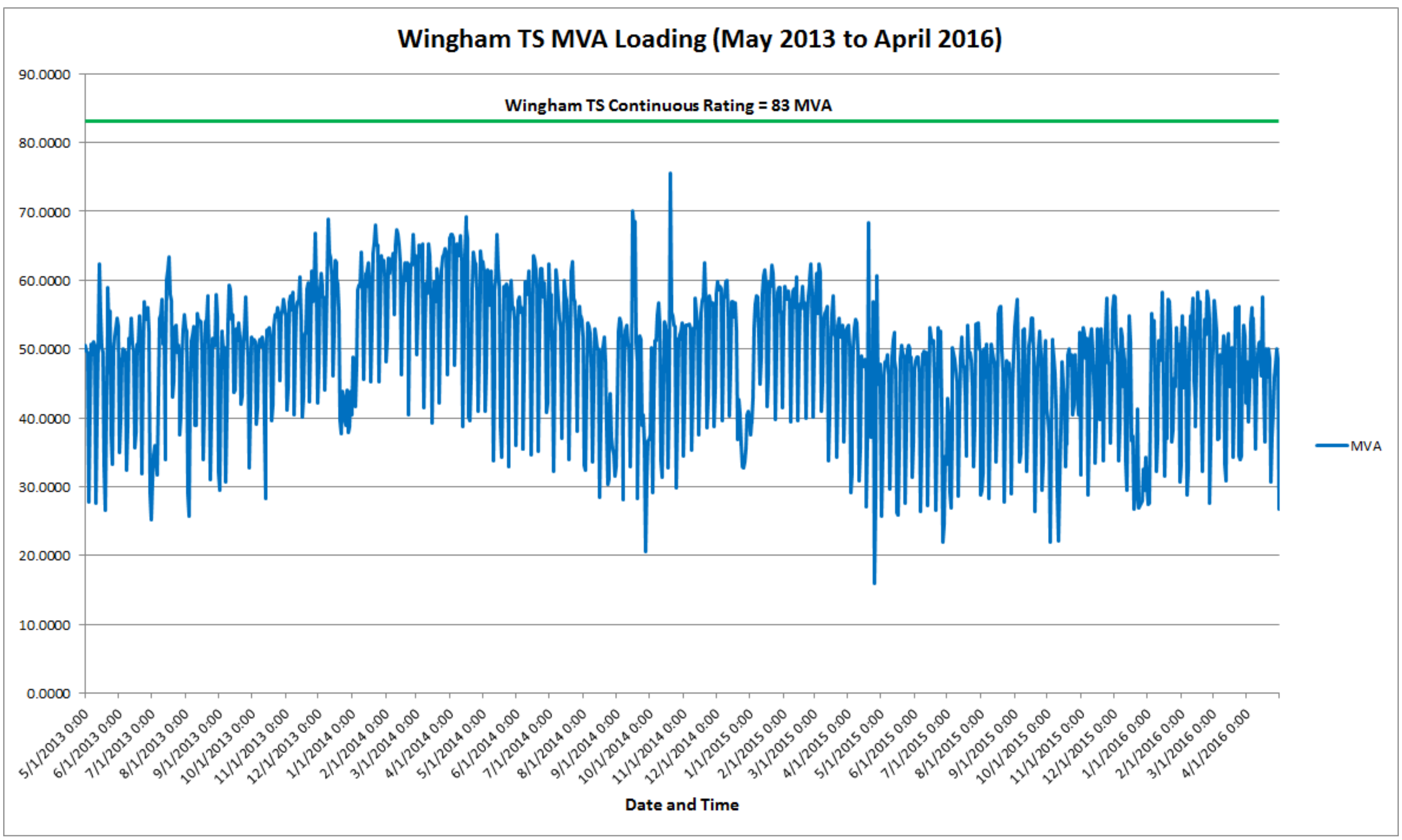

Figure 4: Graph showing MVA loading at Wingham TS over the last 3 years